KEY ENERGY SERVICES INC
Form 424B5
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Prospectus Supplement dated October 1, 2003 to prospectus dated April 24, 2002

Filed Pursuant to Rule 424(b)(5)
File No. 333-83924

542,477 Shares

Key Energy Services, Inc.

Common Stock

This prospectus supplement relates to 542,477 shares of our common stock issued in connection with the acquisition of substantially all of the assets of Lea Fishing Tools, Inc. The terms of this acquisition were determined by direct negotiations with the owners of the business, and the shares of common stock issued are valued at prices reasonably related to current market prices. Our common stock is listed on the New York Stock Exchange under the symbol "KEG." The last reported sale price of our common stock on September 30, 2003 was $9.65 per share.

We will pay all expenses of this offering. No underwriting discounts or commissions will be paid in connection with the issuance of common stock in business combination transactions or acquisitions, although finder's fees may be paid with respect to specific acquisitions. Any person receiving a finder's fee may be deemed to be an underwriter within the meaning of Section 2(11) of the Securities Act of 1933.

Investing in our common stock involves risks. See "Risk Factors" on page 6 of the prospectus dated April 24, 2002.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus supplement or the prospectus. Any representation to the contrary is a criminal offense.

The date of this prospectus supplement is October 1, 2003.

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PROSPECTUS SUPPLEMENT

PROSPECTUS

You should rely only on the information contained in this prospectus and prospectus supplement. We have not authorized anyone to provide you with information that is different. This prospectus supplement and the prospectus may only be used where it is legal to sell these securities. The information in this prospectus and prospectus supplement is only accurate as of the date of this document.

THE OFFERING

Common stock offered	542,477 shares
Common stock to be outstanding after the Offering(1)	130,463,475
Use of proceeds	The shares of common stock offered by this prospectus are being issued in exchange for substantially all the assets of Lea Fishing Tools, Inc. We intend to use the assets in the operation of our business. We will not receive any cash proceeds in exchange for issuance of the shares.
New York Stock Exchange symbol	KEG

(1) Based on 129,920,998 shares of common stock outstanding as of September 30, 2003. Excludes shares of common stock reserved for future issuance.

USE OF PROCEEDS

We will not receive any proceeds of this offering other than the value of the businesses or properties we acquire in the acquisition.

PRICE RANGE OF COMMON STOCK AND DIVIDEND POLICY

Our common stock is currently traded on the New York Stock Exchange, under the symbol "KEG." The following tables sets forth, for the periods indicated, the high and low sales prices of our common stock on the New York Stock Exchange for the fiscal years ending June 30, 2002 and 2001, the Transition Period(1) ending December 31, 2002, and the first three quarters of the fiscal year ending December 31, 2003 as derived from published sources.

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(1) In December 2002, our Board of Directors approved the change of our fiscal year end from June 30 to December 31 of each year. The Transition Period covers July 1, 2002 through December 31, 2002.

	High	Low
Fiscal Year Ending December 31, 2003:		
Third Quarter (as of 9/26/03)	11.08	8.68
Second Quarter	12.38	9.77
First Quarter	11.09	8.49
Transition Period Ending December 31, 2002:		
October 1, 2002 to December 31, 2002	9.88	6.90
July 1, 2002 to September 30, 2002	10.45	7.05
Fiscal Year Ending June 30, 2002:		
Fourth Quarter	12.59	9.60
Third Quarter	11.45	7.20
Second Quarter	9.70	5.99
First Quarter	11.01	5.58
Fiscal Year Ending June 30, 2001:		
Fourth Quarter	15.33	9.55
Third Quarter	13.52	8.8125
Second Quarter	10.50	6.8125
First Quarter	$11\frac{7}{16}$	$7\frac{1}{16}$

We did not pay dividends on our common stock during the fiscal years ended June 30, 2002 or 2001. We do not intend, for the foreseeable future, to pay dividends on our common stock. In addition, we are contractually restricted from paying dividends under the terms of our existing credit facilities.

On September 30, 2003 the last reported sale price for our Common Stock was $9.65 per share.

SELECTED FINANCIAL DATA

	Six Months Ended December 31, 2002(1)	Year Ended June 30, 2002	2001	2000	1999(2)	1998
	(In Thousands, Except Per Share Amounts)					
OPERATING DATA:						
Revenues	$ 408,998	$ 802,564	$ 873,262	$ 637,732	$ 491,817	$ 424,543
Operating costs:						
Direct costs	287,011	554,773	582,154	471,169	374,308	296,328
Depreciation, depletion and amortization	51,111	78,265	75,147	70,972	62,074	31,001
General and administrative	50,155	59,494	60,118	51,637	56,156	36,933
Interest	22,743	43,332	56,560	71,930	67,401	21,476
Foreign currency transaction loss, Argentina		1,443				
Debt Issuance Costs					6,307	
Restructuring Charge					4,504	
Income (loss) before income taxes, minority interest, and cumulative effect	(2,022)	65,257	99,283	(27,976)	(78,933)	38,805
Net income (loss)	(4,376)	38,146	62,710	(18,959)	(53,258)	24,175
Income (loss) per common share:						
Basic	$ (0.03)	$ 0.36	$ 0.63	$ (0.23)	$ (1.94)	$ 1.41
Diluted	$ (0.03)	$ 0.35	$ 0.61	$ (0.23)	$ (1.94)	$ 1.23
Average common shares outstanding:						
Basic	125,367	105,766	98,195	83,815	27,501	17,153
Assuming full dilution	125,367	107,462	102,271	83,815	27,501	24,024
Common shares issued at period end	128,758	110,308	101,440	97,210	82,738	18,267
Market price per common share at period end	$ 8.97	$ 10.50	$ 10.84	9.64	$ 3.56	$ 13.12
Cash dividends paid on common shares						
BALANCE SHEET DATA:						
Cash	$ 9,044	$ 54,147	$ 2,098	$ 109,873	$ 23,478	$ 25,265
Current assets	175,574	192,073	206,150	253,589	132,543	127,557
Property and equipment	1,291,853	1,093,104	1,014,675	920,437	871,940	547,537
Property and equipment, net	956,505	808,900	793,716	760,561	769,562	499,152
Total assets	1,502,002	1,242,995	1,228,284	1,246,265	1,148,138	698,640
Current liabilities	108,875	96,628	115,553	92,848	73,151	48,029
Long-term debt, including current portion	493,565	443,610	493,907	666,600	699,978	399,779
Stockholders' equity	696,368	536,866	476,878	382,887	288,094	154,928
OTHER DATA:						
Net cash provided by (used in) provided by:						
Operating activities	57,594	178,716	143,347	34,860	(13,427)	40,925
Investing activities	(146,073)	(108,749)	(83,980)	(37,766)	(294,654)	(306,339)
Financing activities	44,054	(17,315)	(167,142)	89,301	306,294	248,975
Working capital	66,699	95,445	90,597	160,741	59,392	79,528
Book value per common share(3)	$ 5.41	$ 4.87	$ 4.70	$ 3.94	$ 3.47	$ 8.48

(1) *Financial data for the six months ended December 31, 2002 includes the allocated purchase price of Q Services, Inc. and the results of their operations, beginning July 19, 2002.*

(2) *Financial data for the year ended June 30, 1999 includes the allocated purchase price of Dawson Production Services, Inc. and the results of their operations, beginning September 15, 1998.*

(3) *Book value per common share is stockholders' equity at period end divided by the number of issued common shares at period end.*

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

The statements in this document that relate to matters that are not historical facts are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. When used in this document and the documents incorporated by reference, words such as "anticipate," "believe," "expect," "plan," "intend," "estimate," "project," "will," "could," "may," "predict" and similar expressions are intended to identify forward-looking statements. Further events and actual results may differ materially from the results set forth in or implied in the forward-looking statements. Factors that might cause such a difference include:

- fluctuations in world-wide prices and demand for oil and natural gas;
- fluctuations in the level of oil and natural gas exploration and development activities;
- fluctuations in the demand for well servicing, contract drilling and ancillary oilfield services;
- the existence of competitors, technological changes and developments in the industry;
- the existence of operating risks inherent in the well servicing, contract drilling and ancillary oilfield services; and
- general economic conditions, the existence of regulatory uncertainties, the possibility of political instability in any of the countries in which we conduct business, in addition to the other matters discussed herein.

These forward-looking statements speak only as of the date of this report and we disclaim any duty or obligation to update the forward-looking statement in this report.

The following discussion provides information to assist in the understanding of our financial condition and results of operations. It should be read in conjunction with the consolidated financial statements and related notes appearing elsewhere in this report. References to composite well servicing rig rates means, for a given period, the total well servicing revenues for that period divided by the total well servicing hours for that period. References to composite contract drilling rig rates means, for a given period, the total contract drilling revenues for that period divided by the total contract drilling hours for that period. References to composite truck rates means, for a given period, the total trucking revenues for that period divided by the total trucking hours for that period.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Results Of Operations

Our results of operations for the three and six months ended June 30, 2003 reflect the impact of continued modest improvement in industry conditions resulting from continued strength in oil and natural gas prices.

Three Months Ended June 30, 2003 Versus Three Months Ended June 30, 2002

Our revenue for the three months ended June 30, 2003 increased $69,846,000, or 41%, to $239,595,000 from $169,749,000 for the three months ended June 30, 2002. For the three months ended June 30, 2003, we had a net income of $6,153,000, an improvement of $12,016,000, from a net loss of $5,863,000 for the three months ended June 30, 2002. The increase in revenues and net income is principally due to increasing levels of activity and the acquisition of QSI. Total rig hours for the three months ended June 30, 2003 increased approximately 12% compared to total rig hours for the three months ended June 30, 2002. Total trucking hours for the three months ended June 30, 2003 increased approximately 49% compared to total trucking hours for the three months ended June 30, 2002 principally due to the acquisition of QSI and improved activity levels.

Operating Revenues

Well Servicing. Well servicing revenues for the three months ended June 30, 2003 increased $65,919,000, or 43%, to $219,970,000 from $154,051,000 for the three months ended June 30, 2002. The increase in revenues was primarily due to an increase in activity and the acquisition of QSI resulting in an increase in total well servicing hours and total trucking hours and a slight increase in composite well servicing rig rates. Total well servicing hours for the three months ended June 30, 2003 increased approximately 10% compared to total well servicing hours for the three months ended June 30, 2002. Composite well servicing rig rates increased by approximately 4% for the three months ended June 30, 2003 compared to composite well servicing rig rates for the three months ended June 30, 2002. While total trucking hours for the three months ended June 30, 2003 increased approximately 49% compared to total trucking hours for the three months ended June 30, 2002, composite truck rates for the three months ended June 30, 2003 decreased slightly by approximately 1% compared to composite truck rates for the three months ended June 30, 2002.

Contract Drilling. Contract drilling revenues for the three months ended June 30, 2003 increased $5,381,000, or 41%, to $18,511,000 from $13,130,000 for the three months ended June 30, 2002. The increase in revenues was primarily due to an increase in activity resulting in an increase in total contract drilling hours and a slight improvement in composite contract drilling rates. Total contract drilling hours for the three months ended June 30, 2003 increased by approximately 37% compared to total contract drilling hours for the three months ended June 30, 2002, while composite contract drilling rig rates for the three months ended June 30, 2003 increased by approximately 3% compared to composite contract drilling rig rates for the three months ended June 30, 2002.

Operating Expenses

Well Servicing. Well servicing expenses for the three months ended June 30, 2003 increased $33,330,000, or 28%, to $154,333,000 from $121,003,000 for the three months ended June 30, 2002. The increase was primarily due to increased levels of activity and related repair and maintenance costs, the acquisition of QSI and higher insurance costs, primarily in workers' compensation. Well servicing expenses, as a percentage of well servicing revenue, decreased from 79% for the three months ended June 30, 2002 to 70% for the three months ended June 30, 2003.

Contract Drilling. Contract drilling expenses for the three months ended June 30, 2003 increased $2,802,000, or 27%, to $13,189,000 from $10,387,000 for the three months ended June 30, 2002. The increase was primarily due to increased levels of activity and related repair and maintenance costs and higher insurance costs, primarily workers' compensation. Contract drilling expenses, as a percentage of contract drilling revenues, decreased from 79% for the three months ended June 30, 2002 to 71% for the three months ended June 30, 2003.

Depreciation, Depletion and Amortization Expense

Our depreciation, depletion and amortization expense for the three months ended June 30, 2003 increased $4,907,000, or 24%, to $25,690,000 from $20,783,000 for the three months ended June 30, 2002. The increase is primarily due to acquisition of QSI, which added approximately $114,519,000 in property and equipment, and to a lesser extent by our ongoing capital expenditure program, which includes remanufacturing of well service and contract drilling equipment and our technology initiatives.

General and Administrative Expenses

Our general and administrative expenses for the three months ended June 30, 2003 increased $6,704,000, or 40%, to $23,585,000 from $16,881,000 for the three months ended June 30, 2002. The increase was primarily due to the acquisition of QSI and higher costs associated with increased activity levels. Incremental costs include expenses related to additional personnel supporting the implementation of information technology initiatives. General and administrative expenses, as a percentage of revenues, was 10% for the three months ended June 30, 2003 and for the three months ended June 30, 2002.

Interest Expense

Our interest expense for the three months ended June 30, 2003 increased $1,755,000, or 17%, to $12,166,000 from $10,411,000 for the three months ended June 30, 2002. The increase was primarily due to higher average long term debt in the quarter ended June 30, 2003 as compared to June 30, 2002 resulting from the issuance of the $6^3/_8$% Senior Notes partially offset by the repayment of borrowings outstanding under the revolver and the retirement of a portion of the 5% Convertible Subordinated Notes. Included in interest expense was the amortization of deferred debt issuance costs, discount and premium of approximately $833,000 for the three months ended June 30, 2003 compared to $612,000 for the three months ended June 30, 2002.

Gain (Loss) on Retirement of Debt

During the three months ended June 30, 2003, we repurchased approximately $30,800,000 of our long-term debt at a discount and expense related debt issuance costs which resulted in a gain of $14,000. During the three months ended June 30, 2002, we repurchased approximately $532,000 of our long-term debt at a discount which resulted in a gain of $11,000. On July 1, 2002, we adopted Statement of Financial Accounting Standards No. 145, Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections ("SFAS 145"). The new standard rescinds FASB Statement No. 4, which required all gains and losses from extinguishment of debt to be recorded as extraordinary items.

Income Taxes

Our income tax expense for the three months ended June 30, 2003 increased $8,205,000 to an expense of $3,519,000 from a benefit of $4,686,000 for the three months ended June 30, 2002. Our effective tax rate for the three months ended June 30, 2003 was 36% compared to (44%) for the three

months ended June 30, 2002. The effective tax rates are different from the statutory rate of 35% because of non-deductible expenses and the effects of state, local and foreign taxes.

Cash Flows

Our net cash provided by operating activities for the three months ended June 30, 2003 decreased $4,747,000 to $40,139,000 from $44,886,000 for the three months ended June 30, 2002. The decrease in net cash provided by operating activities was due to an increase in working capital, other assets and liabilities, partially offset by an increase in net income from higher activity levels.

Our net cash used in investing activities for the three months ended June 30, 2003 decreased $4,506,000 to $26,760,000 from $31,266,000 for the three months ended June 30, 2002. The decrease in net cash used in investing activities was due to lower capital expenditures during the three months ended June 30, 2003 over the three months ended June 30, 2002.

Our net cash provided by financing activities for the three months ended June 30, 2003 increased $58,621,000 to $56,515,000 from a use of $2,106,000 for the three months ended June 30, 2002. During the three months ended June 30, 2003, we completed a public offering of $150,000,000 of $6^3/_8$% Senior Notes due 2013. We used a portion of the proceeds to repay our indebtedness under the Senior Credit Facility and to repurchase approximately $30,800,000 of our outstanding 5% Convertible Subordinated Notes.

The effect of exchange rates on cash for the three months ended June 30, 2003 and 2002 was a use of $792,000 and $334,000, respectively. This was principally the result of the change in exchange rates of the Argentina peso for the corresponding periods.

Six Months Ended June 30, 2003 Versus Six Months Ended June 30, 2002

Our revenue for the six months ended June 30, 2003 increased $114,729,000, or 34%, to $454,719,000 from $339,990,000 for the six months ended June 30, 2002. For the six months ended June 30, 2003, we had a net income of $4,379,000, an improvement of $14,868,000, from a net loss of $10,489,000 for the six months ended June 30, 2002. The increase in revenues and increase in net income is principally due to increasing levels of activity and the acquisition of QSI. Total rig hours for the six months ended June 30, 2003 increased approximately 9% compared to total rig hours for the six months ended June 30, 2002. Total trucking hours for the six months ended June 30, 2003 increased approximately 50% compared to total trucking hours for the six months ended June 30, 2002, principally due to the acquisition of QSI and improved activity levels.

Operating Revenues

Well Servicing. Well servicing revenues for the six months ended June 30, 2003 increased $110,643,000, or 36%, to $419,128,000 from $308,485,000 for the six months ended June 30, 2002. The increase in revenues was primarily due to an increase in activity and the acquisition of QSI resulting in an increase in total well servicing hours and total trucking hours and a slight increase in composite well servicing rig rates, partially offset by declines in composite truck rates. Total well servicing hours for the six months ended June 30, 2003 increased approximately 9% compared to total well servicing hours for the six months ended June 30, 2002. Composite well servicing rig rates increased by approximately 2% for the six months ended June 30, 2003 compared to composite well servicing rig rates for the six months ended June 30, 2002. While total trucking hours for the six months ended June 30, 2003 increased by approximately 50% compared to total trucking hours for the six months ended June 30, 2002, composite truck rates for the six months ended June 30, 2003 decreased by approximately 4% compared to composite truck rates for the six months ended June 30, 2002.

Contract Drilling. Contract drilling revenues for the six months ended June 30, 2003 increased $6,014,000, or 22%, to $33,106,000 from $27,092,000 for the six months ended June 30, 2002. The increase in revenues was primarily due to an increase in activity resulting in an increase in contract drilling rig hours and a slight improvement in composite contract drilling rates. Total contract drilling hours for the six months ended June 30, 2003 increased approximately 18% compared to total contract drilling hours for the six months ended June 30, 2002, while composite contract drilling rig rates for the six months ended June 30, 2003 increased by approximately 3% compared to composite contract drilling rig rates for the six months ended June 30, 2002.

Operating Expenses

Well Servicing. Well servicing expenses for the six months ended June 30, 2003 increased $66,877,000, or 29%, to $301,238,000 from $234,361,000 for the six months ended June 30, 2002. The increase was primarily due to increased levels of activity and related repair and maintenance costs, the acquisition of QSI and higher insurance costs, primarily in workers' compensation. Well servicing expenses, as a percentage of well servicing revenue, decreased from 76% for the six months ended June 30, 2002 to 72% for the six months ended June 30, 2003.

Contract Drilling. Contract drilling expenses for the six months ended June 30, 2003 increased $2,884,000, or 13%, to $24,337,000 from $21,453,000 for the six months ended June 30, 2002. The increase was primarily due to increased levels of activity and related repair and maintenance costs and higher insurance costs, primarily in workers' compensation. Contract drilling expenses, as a percentage of contract drilling revenues, decreased from 79% for the six months ended June 30, 2002 to 74% for the six months ended June 30, 2003.

Depreciation, Depletion and Amortization Expense

Our depreciation, depletion and amortization expense for the six months ended June 30, 2003 increased $10,619,000, or 26%, to $51,291,000 from $40,672,000 for the six months ended June 30, 2002. The increase is primarily due to the acquisition of QSI, which added approximately $114,519,000 in property and equipment and to a lesser extent by our ongoing capital expenditure program, which includes remanufacturing of well service and contract drilling equipment and our technology initiatives.

General and Administrative Expenses

Our general and administrative expenses for the six months ended June 30, 2003 increased $15,128,000, or 49%, to $45,703,000, from $30,575,000 for the six months ended June 30, 2002. The increase was primarily due to the acquisition of QSI and higher costs associated with increased activity levels. Incremental costs include expenses related to additional personnel supporting the implementation of information technology initiatives. General and administrative expenses, as a percentage of revenues, increased from 9% for the six months ended June 30, 2002 to 10% for the six months ended June 30, 2003.

Interest Expense

Our interest expense for the six months ended June 30, 2003 increased $2,928,000, or 14%, to $23,214,000 from $20,286,000 for the six months ended June 30, 2002. The increase was primarily due to higher average long term debt in the quarter ended June 30, 2003 as compared to June 30, 2002 resulting from the issuance of the 6$^{3}/_{8}$% Senior Notes partially offset by the repayment of borrowings under the revolver and the retirement of a portion of the 5% Convertible Subordinated Notes. Included in interest expense was the amortization of deferred debt issuance costs, discount and premium of approximately $1,609,000 for the six months ended June 30, 2003 compared to $1,282,000 for the six months ended June 30, 2002.

Gain (Loss) on Retirement of Debt

During the six months ended June 30, 2003, we repurchased approximately $30,855,000 of our long-term debt at a discount and expensed related debt issuance costs which resulted in a gain of $16,000. During the six months ended June 30, 2002, we repurchased approximately $36,050,000 of our long-term debt at various discounts and premiums and expensed related debt issuance costs, which resulted in a loss of $8,457,000. On July 1, 2002, we adopted Statement of Financial Accounting Standards No. 145, Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections ("SFAS 145"). The new standard rescinds FASB Statement No. 4, which required all gains and losses from extinguishment of debt to be recorded as extraordinary items.

Income Taxes

Our income tax expense for the six months ended June 30, 2003 increased $9,804,000 to an expense of $2,684,000 from a benefit of $7,120,000 for the six months ended June 30, 2002. Our effective tax rate for the six months ended June 30, 2003 was 38% compared to (40%) for the six months ended June 30, 2002. The effective tax rates are different from the statutory rate of 35% because of non-deductible expenses and the effects of state, local and foreign taxes.

Cash Flow

Our net cash provided by operating activities for the six months ended June 30, 2003 decreased $26,965,000 to $48,200,000 from $75,165,000 for the six months ended June 30, 2002. The decrease in net cash provided by operating activities was due to an increase in working capital, partially offset by an increase in income from higher activity levels.

Our net cash used in investing activities for the six months ended June 30, 2003 decreased $12,485,000 to $45,582,000 from $58,067,000 for the six months ended June 30, 2002. The decrease in net cash used in investing activities was due to lower capital expenditures and minimal acquisition activity during the six months ended June 30, 2003 over the six months ended June 30, 2002.

Our net cash provided by financing activities for the six months ended June 30, 2003 increased $32,135,000 to $61,629,000 from $29,494,000 for the six months ended June 30, 2002. During the six months ended June 30, 2003, we completed a public offering of $150,000,000 of 6$^{3}/_{8}$% Senior Notes due 2013. We used a portion of the proceeds to repay our indebtedness under the Senior Credit Facility and to repurchase approximately $30,800,000 of our outstanding 5% Convertible Subordinated Notes.

The effect of exchange rates on cash for the six months ended June 30, 2003 and 2002 was a use of $627,000 and $411,000, respectively. This was principally the result of the change in exchange rates of the Argentine peso for the corresponding periods.

Six Months Ended December 31, 2002 Versus Six Months December 31, 2001

Our results of operations for the six months ended December 31, 2002 reflect the general uncertainty about future oil and natural gas prices, including the customers' perception that commodity prices may decrease, which in turn caused a decline in demand for our equipment and services partially offset by minimizing rate concessions.

The Company

Our revenue for the six months ended December 31,2002 decreased $53,576,000, or 11.6%, to $408,998,000 from $462,574,000 for the six months ended December 31, 2001. For the six months ended December 31, 2002, we incurred a net loss of $4,376,000, representing a decrease of $53,011,000, or 109.0%, from net income of $48,635,000, for the six months ended December 31, 2001. The decrease in revenues and net income is principally due to lower levels of activity and lower pricing partially offset by the acquisition of QSI. Total rig hours for the six months ended December 31, 2002 declined approximately 20% compared to total rig hours for the six months ended December 31, 2001 coupled with a decreased in composite well servicing rig rates for the six months ended December 31, 2002 of approximately 7% and composite contract drilling rig rates for the six months ended December 31, 2002 of approximately 7% compared to composite well servicing rig rates and composite contract drilling rig rates for the six months ended December 31, 2001. While trucking hours for the six-month period ended December 31, 2002 increased approximately 29% compared to trucking hours for the six-month period ended December 31, 2001, the increase was principally due to the acquisition of QSI. Further, composite truck rates for the six-month period ended December 31, 2002 declined approximately 16% compared to the composite truck rates for six-month period ended December 31, 2001. The net loss in the six months ended December 31, 2002 was also affected by the cumulative effect of our mandatory adoption of SFAS 143, costs associated with the integration of QSI, and unusually high general liability costs and start-up costs associated with our new Egypt project.

Operating Revenues

Well Servicing. Well servicing revenues for the six months ended December 31, 2002 decreased $27,968,000, or 7.0%, to $370,871,000 from $398,839,000 for the six months ended December 31, 2001. The decrease in revenues was primarily due to a decline in activity and oilfield service rates partially offset by the acquisition of QSI. Well servicing hours for the six months ended December 31, 2002 declined approximately 18% compared to well servicing hours for the six months ended December 31, 2001, which was exacerbated by a decline in composite well servicing rig rates for the six months ended December 31, 2002 of approximately 7% compared to composite well servicing rig rates for the six months ended December 31, 2001. Trucking hours for the six months ended December 31, 2002 increased approximately 28% compared to trucking hours for the six months ended December 31, 2001. The increase was principally due to the acquisition of QSI. Further, composite truck rates for the six months ended December 31, 2002 declined approximately 16% compared to composite truck rates for the six months ended December 31, 2001.

Contract Drilling. Contract drilling revenues for the six months ended December 31, 2002 decreased $25,658,000, or 43.3%, to $33,632,000 from $59,290,000 for the six months ended December 31, 2001. The decrease in revenues was primarily due to a decline in equipment utilization and pricing of contract drilling services. Contract drilling hours for the six months ended December 31, 2002 declined approximately 39% compared to contract drilling hours for the six months ended December 31, 2001. Composite contract drilling rig rates for the six months ended December 31, 2002 declined approximately 7% compared to composite contract drilling rig rates for the six months ended December 31, 2001.

Operating Expenses

Well Servicing. Well servicing expenses for the six months ended December 31, 2002 increased $7,695,000, or 3%, to $263,595,000 from $255,900,000 for the six months ended December 31, 2001. Although well servicing hours decreased, expenses increased due to the acquisition and integration costs associated with QSI, higher insurance costs primarily in workers' compensation and health care, and start-up costs for our new Egypt project. Well servicing expenses as a percentage of well servicing revenues increased from 64.2% for the six months ended December 31, 2001 to 71.1% for the six months ended December 31, 2002.

Contract Drilling. Contract drilling expenses for the six months ended December 31, 2002 decreased $15,112,000, or 39.2%, to $23,416,000 from $38,528,000 for the six months ended December 31, 2001. The decrease is primarily due to lower activity levels, which was partially offset by higher insurance costs primarily in workers' compensation and health care. Contract drilling expenses as

a percentage of contract drilling revenues increased from 65.0% for the six months ended December 31, 2001 to 69.6% for the six months ended December 31, 2002.

Depreciation, Depletion and Amortization Expense

Our depreciation, depletion and amortization expense for the six months ended December 31, 2002 increased $13,518,000, or 36.0%, to $51,111,000 from $37,593,000 for the six months ended December 31, 2001. The increase is primarily due to the acquisition of QSI, which added approximately $142,264,000 in net depreciable assets, and capital expenditures during the prior year as we continued remanufacturing well servicing and contract drilling equipment.

General and Administrative Expenses

Our general and administrative expenses for the six months ended December 31, 2002 increased $19,320,000, or 66.8%, to $48,239,000 from $28,919,000 for the six months ended December 31, 2001. The increase was primarily due to the acquisition of QSI and costs associated with the integration of QSI, higher general liability costs including settlement expenses, and additional personnel supporting the implementation of information technology. General and administrative expenses, as a percentage of revenues, increased from 6.3% for the six months ended December 31, 2001 to 11.8% for the six months ended December 31, 2002.

Interest Expense

Our interest expense for the six months ended December 31, 2002 decreased $303,000, or 1.3%, to $22,743,000 from $23,046,000 for the six months ended December 31, 2001. The restructuring of our long-term debt resulted in a decline in our incremental borrowing rate of approximately 1%. Included in the interest expense was the amortization of debt issuance costs of $2,103,000 and $1,393,000 for the six months ended December 31, 2002 and 2001, respectively.

Gain on Retirement of Debt

During the six months ended December 31, 2002, we repurchased an aggregate principal amount of $397,000 of our long-term debt at various discounts and premiums to par value and expensed related unamortized debt issuance costs, all of which resulted in a gain of $18,000. The repurchase of the long term debt was part of our overall plan to reduce and restructure our long term debt and to restructure debt maturities.

Cumulative Effect on Prior Years of a Change in Accounting Principle

On July 1, 2002, we adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations ("SFAS 143"). Adoption of SFAS 143 is required for all companies with fiscal years beginning after June 15, 2002. The new standard requires us to recognize a liability for the present value of all legal obligations associated with the retirement of tangible long-lived assets and capitalize an equal amount as a cost of the asset depreciating the additional cost over the estimated useful life of the asset. On July 1, 2002, we recorded additional costs, net of accumulated depreciation, of approximately $3,347,000, a non-current liability of approximately $7,980,000 and an after-tax charge of approximately $2,873,000 for the cumulative effect on prior years for depreciation of the additional costs and accretion expense on the liability related to expected abandonment costs of its oil and natural gas producing properties and salt water disposal wells. At December 31, 2002, the asset retirement obligation was $9,231,000, and the increase in the balance from July 1, 2002 of $1,251,000 is due to accretion expense of $226,000 and asset retirement obligations of QSI of $1,025,000 assumed in the purchase transaction. The pro forma amounts of the asset retirement obligation as of June 30, 2002, 2001, 2000 and 1999, were approximately $7,980,000, $7,581,000, $7,182,000 and $6,783,000,

respectively. The pro forma amounts of the asset retirement obligation were measured using information, assumptions and interest rates as of the adoption date of July 1, 2002. Pro forma net income (loss) and related per share amounts for the years ended June 30, 2002, 2001 and 2000, assuming SFAS 143 had been applied in each year are as follows:

	Year Ended		
	2002	2001	2000
	(Thousands, except per share amount)		
Pro forma net income (loss)	$ 37,894	$ 62,460	$ (19,252)
Earnings (loss) per share			
Basic	$ 0.36	$ 0.64	$ (0.23)
Diluted	$ 0.35	$ 0.61	$ (0.23)

Income Taxes

Our income tax expense for the six months ended December 31, 2002 decreased $29,938,000 from an income tax expense of $29,419,000 for the six months ended December 31, 2001 to an income tax benefit of $519,000. The decrease in income tax expense is due to decreased pre-tax income. Our effective tax rate for the six months ended December 31, 2002 and 2001 was 25.7% and 37.7%, respectively. The effective tax rates are different from the statutory rate of 35% primarily because of non-deductible expenses and the effects of state and local taxes.

Cash Flow

Our net cash provided by operating activities for the six months ended December 31, 2002 decreased $45,223,000 to $57,594,000 from $102,817,000 for the six months ended December 31, 2001. The decrease is primarily due to decreased net income.

Our net cash used in investing activities for the six months ended December 31, 2002 increased $96,125,000 to $146,073,000 from $49,948,000 for the six months ended December 31, 2001. Our used cash of approximately $105,365,000 for the purchase of QSI and other smaller acquisitions, which principally accounts for the increase in net cash used in investing activities.

Our net cash provided by financing activities for the six months ended December 31, 2002 was $44,054,000, representing an increase of $90,863,000 from a use of $46,809,000 for the six months ended December 31, 2001. For the six months ended December 31, 2002, we increased net borrowings by $46,685,000 principally in connection with the purchase of QSI.

For the six months ended December 31, 2001, we reduced net borrowings by $90,930,000 which was partially funded by net proceeds of $42,590,000 from an equity offering.

The effect of exchange rates on cash for the six months ended December 31, 2002 and 2001 was a use of $678,000 and $192,000, respectively. This was a result of the devaluation of the Argentine peso for the six months ended December 31, 2002 and 2001.

Year Ended June 30, 2002 Versus Year Ended June 30, 2001

Our results of operations for the year ended June 30, 2002 reflect the impact of a decline in industry conditions resulting from decreased commodity prices (and our customers' perception that commodity prices may decrease further) which in turn caused a decline in demand for our equipment and services partially offset by minimizing rate concessions and lower interest charges during the year ended June 30, 2002.

The Company

Revenues for the year ended June 30, 2002 decreased $70,698,000, or 8.1%, to $802,564,000 from $873,262,000 for the year ended June 30, 2001, while net income for the year ended June 30, 2002 decreased $24,564,000, or 39.2%, to $38,146,000 from a net income of $62,710,000 for the year ended June 30, 2001. The decrease in revenues and net income is due to lower levels of activity partially offset by higher pricing, with lower interest expense from debt reduction also contributing to net income. Composite truck rates for the year ended June 30, 2002 increased approximately 23% compared to composite truck rates for the year ended June 30, 2001. Composite well servicing rig rates and composite contract drilling rig rates for the year ended June 30, 2002 increased approximately 13% and 11%, respectively, compared to composite well servicing rig rates and composite contract drilling rig rates for the year ended June 30, 2001. However, total rig and trucking hours for the year ended June 30, 2002 decreased approximately 14% and 5%, respectively, compared to total rig and trucking hours for the year ended June 30, 2001. In addition, well servicing rig rates and contract drilling rig rates experienced later in the year ended June 30, 2002 had declined significantly from those rates experienced earlier in the period.

Operating Revenues

Well Servicing. Well servicing revenues for the year ended June 30, 2002 decreased $51,644,000, or 6.8%, to $706,629,000 from $758,273,000 for the year ended June 30, 2001. The decrease was due to lower demand for our well servicing equipment and services partially offset by higher pricing. Well servicing hours for the year ended June 30, 2002 decreased approximately 13% compared to well servicing hours for the year ended June 30, 2001, while composite well servicing rig rates for the year ended June 30, 2002 increased approximately 13% compared to composite well servicing rig rates for the year ended June 30, 2001.

Contract Drilling. Contract drilling revenues for the year ended June 30, 2002 decreased $20,562,000, or 19.1%, to $87,077,000 from $107,639,000 for the year ended June 30, 2001. The decrease was due to lower demand for our contract drilling equipment and services partially offset by higher pricing. Contract drilling hours for the year ended June 30, 2002 declined approximately 27% compared to contract drilling hours for the year ended June 30, 2001, while composite contract drilling rig rates for the year ended June 30, 2002 increased approximately 11% compared to composite contract drilling rig rates for the year ended June 30, 2001.

Operating Expenses

Well Servicing. Well servicing expenses for the year ended June 30, 2002 decreased $10,643,000, or 2.1%, to $489,681,000 from $500,324,000 for the year ended June 30, 2001. The decrease in expenses is due to lower activity levels partially offset by higher insurance costs primarily in workers' compensation and health care. Despite the decreased costs, well servicing expenses as a percentage of well servicing revenues increased from 66.0% for the year ended June 30, 2001 to 69.3% for the year ended June 30, 2002 primarily due to the increase in insurance costs.

Contract Drilling. Contract drilling expenses for the year ended June 30, 2002 decreased $16,805,000, or 21.7%, to $60,561,000 from $77,366,000 for the year ended June 30, 2001. The decrease is due to lower activity levels partially offset by higher insurance costs primarily in workers' compensation and health care. Contract drilling expenses as a percentage of contract drilling revenues decreased from 71.9% for the year ended June 30, 2001 to 69.6% for the year ended June 30, 2002. The marginal improvement is due to improved operating efficiencies and the effects of higher pricing partially offset by the increase in insurance costs.

Depreciation, Depletion and Amortization Expense

Our depreciation, depletion and amortization expense for the year ended June 30, 2002 increased $3,118,000, or 4.1%, to $78,265,000 from $75,147,000 for the year ended June 30, 2001. The increase is due to recent acquisitions and increased capital expenditures during the past year as we continued remanufacturing well servicing and contract drilling equipment partially offset by discontinued amortization of goodwill, which amounted to $9,322,000 for the year ended June 30, 2001, because of our adoption of SFAS 142.

General and Administrative Expenses

Our general and administrative expenses for the year ended June 30, 2002 decreased $624,000, or 1.0%, to $59,494,000 from $60,118,000 for the year ended June 30, 2001. The decrease was due to reductions in incentive payroll costs partially offset by additional expenses incurred as a result of moving our headquarters to Midland, Texas from East Brunswick, New Jersey and increases in personnel supporting information technology functions. Despite the decreased costs, general and administrative expenses as a percentage of total revenues increased from 6.9% for the year ended June 30, 2001 to 7.4% for the year ended June 30, 2002.

Interest Expense

Our interest expense for the year ended June 30, 2002 decreased $13,228,000, or 23.4%, to $43,332,000 from $56,560,000 for the year ended June 30, 2001. The decrease was primarily due to a significant reduction in our long-term debt using proceeds from an equity offering, a debt offering and operating cash flow, and to a lesser extent, lower interest rates. Included in the interest expense was the amortization of debt issuance costs of $2,581,000 and $3,578,000 for the years ended June 30, 2002 and 2001, respectively.

Foreign Currency Transaction Loss

During the year ended June 30, 2002, we recorded an Argentine foreign currency transaction loss of approximately $1,443,000 related to dollar-denominated receivables resulting from the recent devaluation of Argentina's currency.

Loss on Retirement of Debt

During the year ended June 30, 2002, we repurchased an aggregate principal amount of $150,908,000 of its long-term debt at various discounts and premiums to par value and expensed related unamortized debt issuance costs, all of which resulted in a loss of $4,812,000. The repurchase of the long-term debt was part of our overall plan to reduce and restructure its long-term debt. The repurchase of the long-term debt was intended to reduce interest rates and restructure debt maturities.

Income Taxes

Our income tax expense for the year ended June 30, 2002 decreased $14,958,000 to $22,299,000 from $37,257,000 for the year ended June 30, 2001. The decrease in income tax expense is due to decreased pre-tax income. Our effective tax rate for the years ended June 30, 2002 and 2001 was 36.9% and 37.3%, respectively. The effective tax rates vary from the statutory federal rate of 35% principally because of the disallowance of certain goodwill amortization (for the year ended June 30, 2001), and other non-deductible expenses and the effects of state and local taxes.

Cash Flow

Our net cash provided by operating activities for the year ended June 30, 2002 increased $35,369,000 to $178,716,000 from $143,347,000 for the year ended June 30, 2001. The increase, despite lower net income for the year ended June 30, 2002 compared to the net income for the year ended June 30, 2001, is primarily due to a decrease in the components of working capital, specifically accounts receivable and accounts payable. The reduction in working capital is primarily due to lower levels of activity.

Our net cash used in investing activities for the year ended June 30, 2002 increased $24,769,000 to $108,749,000 from $83,980,000 for the year ended June 30, 2001. The increase for the year ended June 30, 2002 is due primarily to higher capital expenditures, approximately 13% higher than that incurred in the year ended June 30, 2001, and an increase in acquisitions of well servicing and contract drilling equipment.

Our net cash used in financing activities for the year ended June 30, 2002 decreased $149,827,000 to $17,315,000 from $167,142,000 for the year ended June 30, 2001. The decrease is primarily the result of higher proceeds from debt and equity offerings completed during the year ended June 30, 2002 compared to financing proceeds received in the year ended June 30, 2001. While we continued our debt reduction strategy during the year ended June 30, 2002, total debt reductions for the year ended June 30, 2002 decreased to approximately $51 million compared to the year ended June 30, 2001 of approximately $169 million.

The effect of exchange rates on cash for the year ended June 30, 2002 was a use of $603,000. This was a result of the devaluation of the Argentine peso for the year ended June 30, 2002.

Year Ended June 30, 2001 Versus Year Ended June 30, 2000

Our results of operations for the year ended June 30, 2001 reflect the impact of favorable industry conditions resulting from increased commodity prices which in turn caused increased demand for our equipment and services during the year ended June 30, 2001. The positive impact of this increased demand on our operating results was partially offset by increased operating expenses incurred as a result of the increase in our business activity.

The Company

Revenues for the year ended June 30, 2001 increased $235,530,000, or 36.9%, to $873,262,000 from $637,732,000 for the year ended June 30, 2000, while net income for the year ended June 30, 2001 increased $81,669,000 to $62,710,000 from a net loss of $18,959,000 for the year ended June 30, 2000. The increase in revenues and net income is due to improved operating conditions, higher rig hours, and increased pricing, with lower interest expense from debt reduction also contributing to net income. Total rig and trucking rig hours for the year ended June 30, 2001 increased approximately 18% and 9%, respectively, compared to the total rig and trucking hours for the year ended June 30, 2000. Composite well servicing rig rates and composite contract drilling rig rates for the year ended June 30, 2001 improved approximately 19% and 17%, respectively, compared to composite well servicing rig rates and composite contract drilling rig rates for the year ended June 30, 2000, while composite truck rates for the year ended June 30, 2001 improved approximately 20% compared to composite truck rates for the year ended June 30, 2000.

Operating Revenues

Well Servicing. Well servicing revenues for the year ended June 30, 2001 increased $198,781,000, or 35.5%, to $758,273,000 from $559,492,000 for the year ended June 30, 2000. The increase was due to increased demand for our well servicing equipment and services and higher pricing. Well servicing hours for the year ended June 30, 2001 increased approximately 16% compared to the well servicing hours for the year ended June 30, 2000, while composite well servicing rates for the year ended June 30, 2001 improved approximately 19% compared to the composite well servicing rates for the year ended June 30, 2000.

Contract Drilling. Contract drilling revenues for the year ended June 30, 2001 increased $39,211,000, or 57.3%, to $107,639,000 from $68,428,000 for the year ended June 30, 2000. The increase was due to increased demand for our contract drilling equipment and services and higher pricing. Contract drilling hours for the year ended June 30, 2001 increased approximately 35% compared to the contract drilling hours for the year ended June 30, 2000, while composite contract drilling rates improved approximately 17% compared to the composite contract drilling rates for the year ended June 30, 2000.

Operating Expenses

Well Servicing. Well servicing expenses for the year ended June 30, 2001 increased $91,601,000, or 22.4%, to $500,324,000 from $408,723,000 for the year ended June 30, 2000. The increase in expenses is due to higher utilization of our well servicing equipment, higher labor costs and the overall increase in our well servicing business. Despite the increased costs, well servicing expenses as a percentage of well servicing revenues decreased from 73.1% for the year ended June 30, 2000 to 66.0% for the year ended June 30, 2001. The marginal improvement is due to improved operating efficiencies and the effects of higher pricing.

Contract Drilling. Contract drilling expenses for the year ended June 30, 2001 increased $19,067,000, or 32.7%, to $77,366,000 from $58,299,000 for the year ended June 30, 2000. The increase is due to higher utilization of our contract drilling equipment, higher labor costs and the overall increase in our contract drilling business. Despite the increased costs, contract drilling expenses as a percentage of contract drilling revenues decreased from 85.2% for the year ended June 30, 2000 to 71.9% for the year ended June 30, 2001. The marginal improvement is due to improved operating efficiencies and the effects of higher pricing.

Depreciation, Depletion and Amortization Expense

Our depreciation, depletion and amortization expense for the year ended June 30, 2001 increased $4,175,000, or 5.9%, to $75,147,000 from $70,972,000 for the year ended June 30, 2000. The increase is due to higher capital expenditures incurred during the year ended June 30, 2001 as we remanufactured equipment and increased utilization of our contract drilling equipment (which we depreciate partially based on utilization).

General and Administrative Expenses

Our general and administrative expenses for the year ended June 30, 2001 increased $8,481,000, or 16.4%, to $60,118,000 from $51,637,000 for the year ended June 30, 2000. The increase was due to higher administrative costs resulting from the growth of our operations as a result of improved industry conditions. Despite the increased costs, general and administrative expenses as a percentage of total revenues declined from 8.1% for the year ended June 30, 2000 to 6.9% for the year ended June 30, 2001.

Interest Expense

Our interest expense for the year ended June 30, 2001 decreased $15,370,000, or 21.4%, to $56,560,000 from $71,930,000 for the year ended June 30, 2000. The decrease was primarily due to the impact of the long-term debt reduction during the year ended June 30, 2001 and, to a lesser extent, lower short-term interest rates and borrowing margins on floating rate debt.

Gain on Retirement of Debt

During the year ended June 30, 2001, we repurchased $257,115,000 of its long-term debt at various discounts and premiums to par value and expensed related unamortized debt issue costs, all of which resulted in a gain of $684,000. The repurchase of the long-term debt was made in connection with our overall strategy to reduce and restructure its long-term debt. The repurchase was intended to lower fixed interest rates and restructure debt maturities.

Income Taxes

Our income tax expense for the year ended June 30, 2001 increased $44,083,000 to $37,257,000 from a benefit of $6,826,000 for the year ended June 30, 2000. The increase in income tax expense is due to increased pre-tax income. Our effective tax rate for the years ended June 30, 2001 and 2000 was 37.3% and (26.5)%, respectively. The effective tax rates vary from the statutory federal rate of 35% principally because of certain non-deductible goodwill amortization, other non-deductible expenses and state and local taxes.

Cash Flow

Our net cash provided by operating activities for the year ended June 30, 2001 increased $108,487,000 to $143,347,000 from $34,860,000 for the year ended June 30, 2000. The increase is due to higher revenues resulting from increased demand for our equipment and services and higher pricing, partially offset by higher operating and general and administrative expenses resulting from increased business activity.

Our net cash used in investing activities for the year ended June 30, 2001 increased $46,214,000 to $83,980,000 from $37,766,000 for the year ended June 30, 2000. The increase is due primarily to higher capital expenditures.

Our net cash used in financing activities for the year ended June 30, 2001 increased $256,443,000 to a use of $167,142,000 from cash provided of $89,301,000 for the year ended June 30, 2000. The increase is primarily the result of significant debt reduction during the year ended June 30, 2001, partially offset by proceeds from a debt offering and the exercise of stock options and warrants during the year ended June 30, 2001.

Fiscal Year Ended June 30, 2002 Versus Fiscal Year Ended June 30, 2001

Our results of operations for the year ended June 30, 2002 reflect the impact of a decline in industry conditions resulting from decreased commodity prices (and its customers' perception that commodity prices may decrease further) which in turn caused a decline in demand for our equipment and services partially offset by minimizing rate concessions and lower interest charges during fiscal 2002.

The Company

Revenues for the year ended June 30, 2002 decreased $70,698,000, or 8.1%, to $802,564,000 from $873,262,000 in fiscal 2001, while net income for fiscal 2002 decreased $24,564,000, or 39.2%, to $38,146,000 from a net income of $62,710,000 in fiscal 2001. The decrease in revenues and net income

is due to lower levels of activity partially offset by higher pricing, with lower interest expense from debt reduction also contributing to net income.

Operating Revenues

Well Servicing. Well servicing revenues for the year ended June 30, 2002 decreased $51,644,000, or 6.8%, to $706,629,000 from $758,273,000 in fiscal 2001. The decrease was due to lower demand for our well servicing equipment and services partially offset by higher pricing.

Contract Drilling. Contract drilling revenues for the year ended June 30, 2002 decreased $20,562,000, or 19.1%, to $87,077,000 from $107,639,000 in fiscal 2001. The decrease was due to lower demand for our contract drilling equipment and services partially offset by higher pricing.

Operating Expenses

Well Servicing. Well servicing expenses for the year ended June 30, 2002 decreased $10,643,000, or 2.1%, to $489,681,000 from $500,324,000 in fiscal 2001. The decrease in expenses is due to lower activity levels partially offset by higher insurance costs primarily in workers compensation and health care. Despite the decreased costs, well servicing expenses as a percentage of well servicing revenues increased from 66.0% for fiscal 2001 to 69.3% for fiscal 2002 primarily due to the increase in insurance costs.

Contract Drilling. Contract drilling expenses for the year ended June 30, 2002, decreased $16,805,000, or 21.7%, to $60,561,000 from $77,366,000 in fiscal 2001. The decrease is due to lower activity levels partially offset by higher insurance costs primarily in workers compensation and health care. Contract drilling expenses as a percentage of contract drilling revenues decreased from 71.9% in fiscal 2001 to 69.5% in fiscal 2002. The margin improvement is due to improved operating efficiencies and the effects of higher pricing partially offset by the increase in insurance costs.

Depreciation, Depletion and Amortization Expense

Our depreciation, depletion and amortization expense for the year ended June 30, 2002 increased $3,118,000, or 4.1%, to $78,265,000 from $75,147,000 in fiscal 2001. The increase is due to recent acquisitions and increased capital expenditures during the past year as we continued major refurbishments of well servicing and contract drilling equipment partially offset by discontinued amortization of goodwill, which amounted to $9,322,000 in fiscal 2001, because of our adoption of SFAS 142.

General and Administrative Expenses

Our general and administrative expenses for the year ended June 30, 2002 decreased $624,000, or 1.0%, to $59,494,000 from $60,118,000 in fiscal 2001. The decrease was due to reductions in incentive payroll costs partially offset by additional expenses incurred as a result of moving our corporate headquarters to Midland, Texas from East Brunswick, New Jersey and increases in personnel supporting information technology functions. Despite the decreased costs, general and administrative expenses as a percentage of total revenues increased from 6.9% in fiscal 2001 to 7.4% in fiscal 2002.

Interest Expense

Our interest expense for the year ended June 30, 2002 decreased $13,228,000, or 23.4%, to $43,332,000 from $56,560,000 in fiscal 2001. The decrease was primarily due to a significant reduction in our long-term debt using proceeds from the equity offering, the debt offering and operating cash flow, and to a lesser extent, lower interest rates. Included in the interest expense was the amortization

of debt issuance costs of $2,581,000 and $3,578,000 for the years ended June 30, 2002 and 2001, respectively.

Foreign Currency Transaction Loss

During fiscal 2002, we recorded an Argentine foreign currency transaction loss of approximately $1,443,000 related to dollar-denominated receivables resulting from the recent devaluation of Argentina's currency.

Extraordinary Gain (Loss)

During fiscal 2002, we repurchased $150,908,000 of our long-term debt at various discounts and premiums to par value and expensed related unamortized debt issuance costs, all of which resulted in an after-tax extraordinary loss of $3,037,000.

Income Taxes

Our income tax expense for the year ended June 30, 2002 decreased $12,928,000 to $24,074,000 from $37,002,000 in fiscal 2001. The decrease in income tax expense is due to decreased pre-tax income. Our effective tax rate for fiscal 2002 and 2001 was 36.9% and 37.3%, respectively. The effective tax rates vary from the statutory federal rate of 35% principally because of the disallowance of certain goodwill amortization (for the year ended June 30, 2001), and other non-deductible expenses and the effects of state and local taxes.

Cash Flow

Our net cash provided by operating activities for the year ended June 30, 2002 increased $35,369,000 to $178,716,000 from $143,347,000 in fiscal 2001. The increase, despite lower net income in fiscal 2002, is primarily due to a decrease in accounts receivable in fiscal 2002 compared to an increase in accounts receivable in fiscal 2001.

Our net cash used in investing activities for the year ended June 30, 2002 increased $24,769,000 to $108,749,000 from $83,980,000 in fiscal 2001. The increase is due primarily to higher capital expenditures and an increase in acquisitions.

Our net cash used in financing activities for the year ended June 30, 2002 decreased $149,827,000 to $17,315,000 from $167,142,000 in fiscal 2001. The decrease is primarily the result of higher proceeds from debt and equity offerings in fiscal 2002 compared to fiscal 2001. While we continued our strategy and significantly reduced debt in fiscal 2002, total debt reductions in fiscal 2002 decreased compared to fiscal 2001.

The effect of exchange rates on cash for the year ended June 30, 2002 was a use of $603,000. This was a result of the devaluation of the Argentine peso in fiscal 2002.

Fiscal Year Ended June 30, 2001 Versus Fiscal Year Ended June 30, 2000

Our results of operations for the year ended June 30, 2001 reflect the impact of favorable industry conditions resulting from increased commodity prices which in turn caused increased demand for our equipment and services during fiscal 2001. The positive impact of this increased demand on our operating results was partially offset by increased operating expenses incurred as a result of the increase in our business activity.

The Company

Revenues for the year ended June 30, 2001 increased $235,530,000, or 36.9%, to $873,262,000 from $637,732,000 in fiscal 2000, while net income for fiscal 2001 increased $81,669,000 to $62,710,000 from a net loss of $18,959,000 in fiscal 2000. The increase in revenues and net income is due to improved operating conditions, higher rig hours, and increased pricing, with lower interest expense from debt reduction also contributing to net income.

Operating Revenues

Well Servicing. Well servicing revenues for the year ended June 30, 2001 increased $198,781,000 or 35.5%, to $758,273,000 from $559,492,000 in fiscal 2000. The increase was due to increased demand for our well servicing equipment and services and higher pricing.

Contract Drilling. Contract drilling revenues for the year ended June 30, 2001 increased $39,211,000, or 57.3%, to $107,639,000 from $68,428,000 in fiscal 2000. The increase was due to increased demand for our contract drilling equipment and services and higher pricing.

Operating Expenses

Well Servicing. Well servicing expenses for the year ended June 30, 2001 increased $91,601,000, or 22.4%, to $500,324,000 from $408,723,000 in fiscal 2000. The increase in expenses is due to higher utilization of our well servicing equipment, higher labor costs and the overall increase in our well servicing business. Despite the increased costs, well servicing expenses as a percent of well servicing revenues decreased from 73.1% for fiscal 2000 to 66.0% for fiscal 2001. The margin improvement is due to improved operating efficiencies and the effects of higher pricing.

Contract Drilling. Contract drilling expenses for the year ended June 30, 2001, increased $19,067,000, or 32.7%, to $77,366,000 from $58,299,000 in fiscal 2000. The increase is due to higher utilization of our contract drilling equipment, higher labor costs and the overall increase in our contract drilling business. Despite the increased costs, contract drilling expenses as a percentage of contract drilling revenues decreased from 85.2% in fiscal 2000 to 71.9% in fiscal 2001. The margin improvement is due to improved operating efficiencies and the effects of higher pricing.

Depreciation, Depletion And Amortization Expense

Our depreciation, depletion and amortization expense for the year ended June 30, 2001 increased $4,175,000, or 5.9%, to $75,147,000 from $70,972,000 in fiscal 2000. The increase is due to higher capital expenditures incurred during fiscal 2001 as we refurbished equipment and increased utilization of our contract drilling equipment (which we depreciates partially based on utilization).

General And Administrative Expenses

Our general and administrative expenses for the year ended June 30, 2001 increased $8,481,000, or 16.4%, to $60,118,000 from $51,637,000 in fiscal 2000. The increase was due to higher administrative costs resulting from the growth of our operations as a result of improved industry conditions. Despite the increased costs, general and administrative expenses as a percentage of total revenues declined from 8.1% in fiscal 2000 to 6.9% in fiscal 2001.

Interest Expense

Our interest expense for the year ended June 30, 2001 decreased $15,370,000, or 21.4%, to $56,560,000 from $71,930,000 in fiscal 2000. The decrease was primarily due to the impact of the long-term debt reduction during fiscal 2001 and, to a lesser extent, lower short-term interest rates and borrowing margins on floating rate debt.

Extraordinary Gain

During fiscal 2001, we repurchased $257,115,000 of its long-term debt at various discounts and premiums to par value and expensed related unamortized debt issue costs, all of which resulted in an after-tax extraordinary gain of $429,000.

Income Taxes

Our income tax expense for the year ended June 30, 2001 increased $44,408,000 to $37,002,000 from a benefit of $7,406,000 in fiscal 2000. The increase in income tax expense is due to increased pre-tax income. Our effective tax rate for fiscal 2001 and 2000 was 37.3% and (26.5)%, respectively. The effective tax rates vary from the statutory federal rate of 35% principally because of certain non-deductible goodwill amortization, other non-deductible expenses and state and local taxes.

Cash Flow

Our net cash provided by operating activities for the year ended June 30, 2001 increased $108,487,000 to $143,347,000 from $34,860,000 in fiscal 2000. The increase is due to higher revenues resulting from increased demand for our equipment and services and higher pricing, partially offset by higher operating and general and administrative expenses resulting from increased business activity.

Our net cash used in investing activities for the year ended June 30, 2001 increased $46,214,000 to $83,980,000 from $37,766,000 in fiscal 2000. The increase is due primarily to higher capital expenditures.

Our net cash used in financing activities for the year ended June 30, 2001 increased $256,443,000 to a use of $167,142,000 from cash provided of $89,301,000 in fiscal 2000. The increase is primarily the result of significant debt reduction during fiscal 2001, partially offset by proceeds from our fiscal 2001 debt offering and the exercise of stock options and warrants.

LIQUIDITY AND CAPITAL RESOURCES

We have historically funded our operations, acquisitions, capital expenditures and working capital requirements from cash flow from operations, bank borrowings and the issuance of equity and long-term debt. We believe that our current reserves of cash and cash equivalents, availability of our existing credit lines, access to capital markets and internally generated cash flows from operations are sufficient to finance the cash requirements of our current cash and future operations, acquisitions and capital expenditures.

Long-Term Debt

Other than capital lease obligations and miscellaneous notes payable, as of June 30, 2003, our long-term debt was comprised of (i) a senior credit facility, (ii) a series of $6^3/_8$% Senior Notes due 2013, (iii) a series of $8^3/_8$% Senior Notes due 2008, (iv) a series of 14% Senior Subordinated Notes due 2009, and (v) a series of 5% Convertible Subordinated Notes due 2004.

Senior Credit Facility. On July 15, 2002, we entered into a Third Amended and Restated Credit Agreement, as subsequently amended (the "Senior Credit Facility"). The Senior Credit Facility consists of a $150,000,000 revolving loan facility with a $75,000,000 sublimit for letters of credit. The loans are secured by most of our tangible and intangible assets. The revolving loan commitment will terminate on July 15, 2005 and all revolving loans must be paid on or before that date. The revolving loans bear interest based upon, at our option, the prime rate plus a variable margin of 0.00% to 1.00% or a Eurodollar rate plus a variable margin of 1.75% to 3.00%. The Senior Credit Facility has customary affirmative and negative covenants including a maximum leverage ratio, a minimum fixed charge coverage ratio and a minimum net worth, as well as limitations on liens and indebtedness and restrictions on dividends, acquisitions and dispositions. As of June 30, 2003, we were in compliance with all covenants contained in the Senior Credit Facility.

As of June 30, 2003, no revolving loans were outstanding under the revolving loan facility and approximately $49,430,000 of letters of credit related to workers' compensation insurance were outstanding. A portion of the net cash proceeds from the debt offering of the 6^3/8% Senior Notes completed in May 2003 were used to repay the balance of the revolving loan facility then outstanding under the Senior Credit Facility.

6^3/8% Senior Notes

On May 14, 2003, we completed a public offering of $150,000,000 of 6^3/8% Senior Notes due 2013 (the "6^3/8% Senior Notes"). The net cash proceeds from the public offering, net of fees and expenses, were used to repay the balance of the revolving loan facility then outstanding under the Senior Credit Facility, with the remainder to be used for general corporate purposes, including further debt retirement. The 6^3/8% Senior Notes are senior unsecured obligations and are fully and unconditionally guaranteed by substantially all of our subsidiaries. The 6^3/8% Senior Notes are effectively subordinated to Key's secured indebtedness, which includes borrowings under the Senior Credit Facility.

At any time and from time to time, we may, at our option, redeem all or a portion of the 6^3/8% Senior Notes, upon not less than 30 and not more than 60 days prior notice, at the make-whole- price, plus accrued and unpaid interest to the redemption date. The make-whole-price is the sum of the outstanding principal amount of the notes to be redeemed plus an amount equal to the excess, if any, of (i) the present value of the remaining interest (excluding payments of interest accrued as of the redemption date), premium and principal payments due on the notes to be redeemed, computed at a discount rate equal to the treasury rate plus 50 basis points, over (ii) the outstanding principal amount of such notes.

At June 30, 2003, $150,000,000 principal amount of the 6^3/8% Senior Notes remained outstanding. The 6^3/8% Senior Notes require semi-annual interest payments on May 15 and November 15 of each year. As of June 30, 2003, we were in compliance with all covenants contained in the 6^3/8% Senior Notes indenture.

8^3/8% Senior Notes

On March 6, 2001, we completed a private placement of $175,000,000 of 8^3/8% Senior Notes due 2008 (the "8^3/8% Senior Notes"). The net cash proceeds from the private placement were used to repay all of the remaining balance of the original term loans under our then outstanding senior credit facility (the "Prior Senior Credit Facility") and a portion of the revolving loan facility under the Prior Senior Credit Facility then outstanding. On March 1, 2002, we completed a public offering of an additional $100,000,000 of 8^3/8% Senior Notes due 2008. The net cash proceeds from the public offering were used to repay all of the remaining balance of the revolving loan facility under the Prior Senior Credit Facility. The 8^3/8% Senior Notes are senior unsecured obligations and are fully and unconditionally guaranteed by substantially all of our subsidiaries. The 8^3/8% Senior Notes are effectively subordinated to our secured indebtedness, which includes borrowings under the Senior Credit Facility.

On and after March 1, 2005, we may redeem some or all of the 8^3/8% Senior Notes at any time at varying redemption prices in excess of par, plus accrued interest. In addition, before March 1, 2004, we may redeem up to 35% of the aggregate principal amount of the 8^3/8% Senior Notes with the proceeds of certain sales of equity at 108.375% of par plus accrued interest.

At June 30, 2003, $275,000,000 principal amount of the 8^3/8% Senior Notes remained outstanding. The 8^3/8% Senior Notes require semi-annual interest payments on March 1 and September 1 of each

year. Interest of approximately $11,516,000 was paid on March 1, 2003. As of June 30, 2003, we were in compliance with all covenants contained in the 8^3/8% Senior Notes indenture.

14% Senior Subordinated Notes

On January 22, 1999, we completed the private placement of 150,000 units (the "Units") consisting of $150,000,000 of 14% Senior Subordinated Notes due 2009 (the "14% Senior Subordinated Notes") and 150,000 warrants to purchase 2,173,433 shares of our common stock at an exercise price of $4.88125 per share (the "Unit Warrants"). The net cash proceeds from the private placement were used to repay substantially all of the remaining $148,600,000 principal amount (plus accrued interest) owed under our bridge loan facility arranged in connection with the acquisition of Dawson Production Services, Inc. ("Dawson").

On and after January 15, 2004, we may redeem some or all of the 14% Senior Subordinated Notes at any time at varying redemption prices in excess of par, which as of January 15, 2004 will be 107% of par, plus accrued interest. In addition, before January 15, 2002, we were allowed to redeem up to 35% of the aggregate principal amount of the 14% Senior Subordinated Notes at 114% of par plus accrued interest with the proceeds of certain sales of equity. During the fiscal year ended June 30, 2001, we exercised our right of redemption for $10,313,000 principal amount of the 14% Senior Subordinated Notes at a price of 114% of the principal amount plus accrued interest. This transaction resulted in a loss of approximately $2,561,000. On January 14, 2002, we exercised our right of redemption for $35,403,000 principal amount of the 14% Senior Subordinated Notes at a price of 114% of the principal amount plus accrued interest. This transaction resulted in a loss of approximately $8,468,000. Also, during the fiscal year ended June 30, 2002, we purchased and canceled $6,784,000 principal amount of the 14% Senior Subordinated Notes at a price of 116% of the principal amount plus accrued interest. These transactions resulted in a loss of approximately $1,821,000.

The Unit Warrants separated from the 14% Senior Subordinated Notes and became exercisable on January 25, 2000. On the date of issuance, the value of the Unit Warrants was estimated at $7,434,000 and is classified as a discount to the 14% Senior Subordinated Notes on our consolidated balance sheet. The discount is being amortized to interest expense over the term of the 14% Senior Subordinated Notes. The 14% Senior Subordinated Notes mature and the Unit Warrants expire on January 15, 2009. The 14% Senior Subordinated Notes are subordinate to our senior indebtedness, which includes borrowings under the Senior Credit Facility, the $8^3/_8$% Senior Notes and the $6^3/_8$% Senior Notes. The 14% Senior Subordinated Notes are fully and unconditionally guaranteed by substantially all of our subsidiaries.

At June 30, 2003, $97,500,000 principal amount of the 14% Senior Subordinated Notes remained outstanding. The 14% Senior Subordinated Notes pay interest semi-annually on January 15 and July 15 of each year. Interest of approximately $6,825,000 was paid on January 15, 2003. As of June 30, 2003, 63,500 Unit Warrants had been exercised, producing approximately $4,173,000 of proceeds for us and leaving 86,500 Unit Warrants outstanding. As of June 30, 2003, we were in compliance with all covenants contained in the 14% Senior Subordinated Notes.

5% Convertible Subordinated Notes

In 1997, we completed a private placement of $216,000,000 of 5% Convertible Subordinated Notes due 2004 (the "5% Convertible Subordinated Notes"). The 5% Convertible Subordinated Notes are subordinate to our senior indebtedness which includes borrowings under the Senior Credit Facility, the 14% Senior Subordinated Notes, the $8^3/_8$% Senior Notes and the $6^3/_8$% Senior Notes. The 5% Convertible Subordinated Notes are convertible, at the holder's option, into shares of our common stock at a conversion price of $38.50 per share, subject to certain adjustments. The 5% Convertible Subordinated Notes are redeemable, at our option, on and after September 15, 2000, in whole or part, together with accrued and unpaid interest. The initial redemption price is 102.86% for the year beginning September 15, 2000 and declines ratably thereafter on an annual basis.

During the three months ended June 30, 2003, we repurchased (and canceled) $30,800,000 principal amount of the 5% Convertible Subordinated Notes, leaving $18,699,000 outstanding as of June 30, 2003. These repurchases resulted in a gain of approximately $14,000. Interest on the 5% Convertible Subordinated Notes is payable on March 15 and September 15 of each year. Interest of approximately $1,237,000 was paid on March 15, 2003. As of June 30, 2003, we were in compliance with all covenants contained in the 5% Convertible Subordinated Notes indenture.

Critical Accounting Policies

We follow certain significant accounting policies when preparing our consolidated financial statements. A complete summary of these policies is included in Note 1 to the consolidated financial statements included in our Transition Report on Form 10-K as of and for the six months ended December 31, 2002.

Certain of the policies require management to make significant and subjective estimates, which are sensitive to deviations of actual results from management's assumptions. In particular, management makes estimates regarding the fair value of our reporting units in assessing potential impairment of goodwill. In addition, we make estimates regarding future undiscounted cash flows from the future use of long-lived assets whenever events or changes in circumstances indicate that the carrying amount of a long-lived asset may not be recoverable.

In assessing impairment of goodwill, we have used estimates and assumptions in estimating the fair value of our reporting units. Actual future results could be different than the estimates and assumptions used. Events or circumstances which might lead to an indication of impairment of goodwill would include, but might not be limited to, prolonged decreases in expectations of long-term well servicing and/or drilling activity or rates brought about by prolonged decreases in oil or natural gas prices, changes in government regulation of the oil and natural gas industry or other events which could affect the level of activity of exploration and production companies.

In assessing impairment of long-lived assets other than goodwill where there has been a change in circumstances indicating that the carrying amount of a long-lived asset may not be recoverable, we have estimated future undiscounted net cash flows from use of the asset based on actual historical results and expectations about future economic circumstances including oil and natural gas prices and operating costs. The estimate of future net cash flows from use of the asset could change if actual prices and costs differ due to industry conditions or other factors affecting our performance.

RECENTLY ISSUED FINANCIAL ACCOUNTING STANDARDS

In April 2003, the FASB issued Statement of Financial Accounting Standards No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities ("SFAS 149"). SFAS 149 amendments require that contracts with comparable characteristics be accounted for similarly, clarifies when a contract with an initial investment meets the characteristic of a derivative and clarifies when a

derivative requires special reporting in the statement of cash flows. SFAS 149 is effective for hedging relationships designated and for contracts entered into or modified after June 30, 2003, except for provisions that relate to SFAS 133 Statement Implementation Issues that have been effective for fiscal quarters prior to June 15, 2003, which should be applied in accordance with their respective effective dates, and certain provisions relating to forward purchases or sales of when-issued securities or other securities that do not exist, which should be applied to existing contracts as well as new contracts entered into after June 30, 2003. The application of SFAS 149 is not expected to have a material effect on our consolidated financial statements.

In May 2003, the FASB issued Statement of Financial Accounting Standards No. 150, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity ("SFAS 150"). SFAS 150 establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. It requires that an issuer classify a financial instrument that is within the scope of SFAS 150 as a liability (or an asset in some circumstances). Many of those instruments were previously classified as equity. The application of SFAS 150 is not expected to have a material effect on our consolidated financial statements. This Statement is effective for financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Special Note: Certain statements set forth below under this caption constitute "forward-looking statements." See "Cautionary Note Regarding Forward-Looking Statements" for additional factors relating to such statements.

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risk. The term "market risk" refers to the risk of loss arising from adverse changes in foreign currency exchange, interest rates and oil and natural gas prices. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures.

INTEREST RATE RISK

At June 30, 2003, we had long-term debt and capital lease obligations outstanding of approximately $558,700,000. Of this amount, approximately $539,572,000, or 97%, bears interest at fixed rates as follows:

	As of June 30, 2003

	As of June 30, 2003
	(Thousands)
6 3/8% Senior Notes Due 2013	$ 150,000
8 3/8% Senior Notes due 2008	276,225
14% Senior Subordinated Notes Due 2009	94,578
5% Convertible Subordinated Notes Due 2004	18,699
Other at 8.0%	70
	$ 539,572

The remaining $19,128,000 of long-term debt and capital lease obligations outstanding as of June 30, 2003 bears interest at floating rates, which averaged approximately 3.1% at June 30, 2003. A 10% increase in short-term interest rates on the floating-rate debt outstanding at June 30, 2003 would equal approximately 31 basis points. Such an increase in interest rates would increase our 2003 annual interest expense by approximately $100,000 assuming borrowed amounts remain outstanding.

The above sensitivity analysis for interest rate risk excludes accounts receivable, accounts payable and accrued liabilities because of the short-term maturity of such instruments.

FOREIGN CURRENCY RISK

During the year ended June 30, 2002, the Argentine government suspended the law tying the Argentine peso to the U.S. dollar at the conversion ratio of 1:1 and created a dual currency system in Argentina. Our net assets of our Argentina subsidiaries are based on the U.S. dollar equivalent of such amounts measured in Argentine pesos as of June 30, 2003 and December 31, 2002. Assets and liabilities of the Argentine operations were translated to U.S. dollars at June 30, 2003 and December 31, 2002 using the applicable free market conversion ratio of 2.8:1 and 3.4:1, respectively, and will be translated at future dates using the applicable free market conversion ratio on such dates. Our net earnings and cash flows from our Argentina subsidiaries are based on the U.S. dollar equivalent of such amounts measured in Argentine pesos. Revenues, expenses and cash flows will be translated using the average exchange rates.

The change in the Argentine peso to the U.S. dollar exchange rate since December 31, 2002 has increased stockholders' equity by approximately $4,482,000, through a credit to other comprehensive loss through June 30, 2003.

Our net assets, net earnings and cash flows from our Canadian subsidiary are based on the U.S. dollar equivalent of such amounts measured in Canadian dollars. Assets and liabilities of the Canadian operations are translated to U.S. dollars using the applicable exchange rate as of the end of a reporting period. Revenues and expenses are translated using the average exchange rate during the reporting period.

A 10% change in the Canadian-to-U.S. Dollar exchange rate would not be material to our net assets, net earnings or cash flows.

Our net assets, net earnings and cash flows from our Egyptian subsidiary are based on the U.S. dollar. Foreign currency transactions are included in determination of net income for the period.

COMMODITY PRICE RISK

Our major market risk exposure for our oil and natural gas production operations is in the pricing applicable to our oil and natural gas sales. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices for natural gas. Pricing for oil and natural gas production has been volatile and unpredictable for many years.

We periodically hedge a portion of our oil and natural gas production through collar and option agreements. The purpose of the hedges is to provide a measure of stability in the volatile environment of oil and natural gas prices and to manage exposure to commodity price risk under existing sales commitments. Our risk management objective is to lock in a range of pricing for expected production volumes. This allows us to forecast future earnings within a predictable range. We meet this objective by entering into collar and option arrangements which allow for acceptable cap and floor prices.

As of June 30, 2003, we had an oil put option in place, as detailed in the following table. Hedged oil volumes as a percentage of actual production was 38% for the three months ended June 30, 2003. A 10% variation in the market price of oil or natural gas from their levels at June 30, 2003 would have no material impact on our net assets, net earnings or cash flows (as derived from commodity option contracts).

The following table sets forth the future volumes hedged by year and the weighted-average strike price of the option contracts at June 30, 2003 and 2002:

	Oil (Bbls)	Natural Gas (Mmbtus)	Term	Strike Price Per Bbl/Mmbtu Floor	Strike Price Per Bbl/Mmbtu Cap	Fair Value
At June 30, 2003						
Oil Put	4,000		Mar 2003 - Feb 2004	$ 21.00		$ 7,000
At June 30, 2002						
Oil Put	5,000		Mar 2002 - Feb 2003	$ 22.00		$ 24,000
Oil Put	4,000		Mar 2003 - Feb 2004	$ 21.00		$ 118,000
Natural Gas Put		75,000	Mar 2002 - Feb 2003	$ 3.00		$ 104,000

(The strike prices for the oil puts are based on the NYMEX spot prices for West Texas Intermediate. The strike price for the natural gas put is based on the Inside FERC-El Paso Permian spot price.)

BUSINESS

The Company

Based on the number of rigs owned and available industry data, we are the largest onshore, rig-based well servicing contractor in the world, with approximately 1,489 well service rigs and 2,295 oilfield service vehicles as of December 31, 2002. We provide a complete range of well services to major oil companies and independent oil and natural gas production companies, including: rig-based well maintenance, workover, completion, and recompletion services (reentering a well to complete the well in a new zone or formation) (including horizontal recompletions); well intervention services; oilfield trucking services; and ancillary oilfield services. We conduct well servicing operations onshore the continental United States in the following regions: Gulf Coast (including South Texas, Central Gulf Coast of Texas and South Louisiana), Permian Basin of West Texas and Eastern New Mexico, Mid-Continent (including the Anadarko, Hugoton and Arkoma Basins, Fort Worth Basin and the ArkLaTex region), Four Corners (including the San Juan, Piceance, Uinta, and Paradox Basins), Eastern (including the Appalachian, Michigan and Illinois Basins), Rocky Mountains (including the Denver-Julesberg, Powder River, Wind River, Green River and Williston Basins), and California (the San Joaquin Basin), and internationally in Argentina, Egypt and Canada (Ontario). Based on the number of rigs owned and available industry data, we are also a leading onshore drilling contractor, with approximately 79 land drilling rigs as of December 31, 2002. We conduct land drilling operations in a number of major domestic producing basins, as well as in Argentina and in Canada (Ontario). We also produce and develop oil and natural gas reserves in the Permian Basin region and Texas Panhandle.

Our principal executive office is located at 6 Desta Drive, Midland, Texas 79705. Our phone number is (915) 620-0300 and our website address is www.keyenergy.com. We make available free of charge through our website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to those reports as soon as reasonably practicable after such material is electronically filed with the Securities and Exchange Commission. Information on our website is not a part of this report.

Business Strategy

We have built our leadership position through the acquisition and consolidation of smaller, regional competitors. This consolidation of assets and employees, together with a continuing decline in the number of available domestic well service rigs due to attrition, cannibalization and transfers outside of the United States, has given us the opportunity to strengthen our position within the industry during the year ended June 30, 2002 and the six-month period ended December 31, 2002. We have focused on maximizing results by reducing debt, building strong customer alliances, refurbishing rigs and related equipment, and training personnel to maintain a qualified and safe employee base.

Reducing Debt. An important element of our long-term business strategy is to reduce our debt and strengthen our balance sheet by repaying debt using a portion of available operating cash flow and by restructuring its debt to minimize cash interest expense and restructure debt maturities. Since March 1999, we have reduced our long-term funded debt net of cash ("net funded debt") and our net funded debt to capitalization ratio from $839,270 and 87.5%, respectively, to $484,521 and 41.0%, respectively, as of December 31, 2002. In addition, during the six-month period ended December 31, 2002, we restructured our senior credit facility in order to increase our borrowing capacity with a minimal effect on interest expense. We expect to be able to continue to reduce debt and strengthen our balance sheet in the future.

Building Strong Customer Alliances. We seek to maximize customer satisfaction by offering a broad range of equipment and services combined with a highly trained and motivated labor force. As a result, we are able to offer proactive solutions for most of our customer's wellsite needs. We ensure consistent high standards of quality and customer satisfaction by continually evaluating our performance. We maintain strong alliances with major oil companies as well as numerous independent oil and natural gas production companies and believe that such alliances improve the stability of demand for our oilfield services.

Remanufacturing Rigs and Related Equipment. We intend to continue actively remanufacturing our rigs and related equipment to maximize the utilization of our rig fleet. We believe that we have adequate cash flow and resources necessary to continue to make the capital expenditures required to continue our remanufacturing program.

Training and Developing Employees. We have, and will continue to, devote significant resources to the training and professional development of our employees with a special emphasis on safety. We currently have two training centers in Texas, one training center in New Mexico and one training center in California to improve our employees' understanding of operating and safety procedures. We recognize the historically high turn-over rate in the industry and are committed to offering compensation, benefits and incentive programs for our employees that are attractive and competitive in our industry, in order to ensure a steady stream of qualified, safety-conscious personnel to provide quality service to our customers.

Developments During and Subsequent to the Six Months Ended December 31, 2002

Change In Fiscal Year End. In December 2002, our Board of Directors approved the change of our fiscal year end from June 30 to December 31 of each year. The transition period covers July 1, 2002 through December 31, 2002 (referred to as "the six month period ended December 31, 2002" or the "Transition Period").

Industry Conditions. During the Transition Period, operating conditions improved modestly; however, demand for services remained comparatively weak given the underlying strength of commodity prices and the historical relationship between commodity prices and activity levels. Although WTI Cushing prices for light sweet crude averaged approximately $28.49 per barrel during the Transition Period and Nymex Henry Hub natural gas prices averaged approximately $3.76 per MMbtu during the Transition Period, as compared to an average WTI Cushing price for light sweet crude of $23.81 per barrel and an average Nymex Henry Hub natural gas price of $2.77 per MMbtu during the fiscal year ended June 30, 2002, we did not experience a corresponding increase in our well servicing business. We

believe the causes for this disparity include: (i) high natural gas inventories at the beginning of the Transition Period, which may have caused some of our customers to question the sustainability of the then current high natural gas price; (ii) negative impact on customers' hedging positions caused by the financial collapse of dominant counter-parties such as Enron and Dynegy; (iii) limited access to the capital markets for small to mid-size independents oil and natural gas production companies for development projects; (iv) focus by customers on use of cash flow for debt reduction or share repurchase programs; (iv) uncertainty over the war in Iraq and political instability in the Middle East; and (v) overall concern about the U.S. and world economies.

Management believes that the current natural gas supply and storage conditions combined with declining U.S. natural gas production will eventually lead to increased demand for natural gas drilling. Furthermore, we believe that oilfield service activity, including well servicing, oilfield trucking and land drilling, tends to lag our customers' cash flows by several quarters which would imply that activity could improve during the later part of 2003.

The level of our revenues, cash flows, losses and earnings are substantially dependent upon, and affected by, the level of domestic and international oil and gas exploration and development activity (Management's Discussion and Analysis of Results of Operations and Financial Condition).

Acquisitions

Q Services, Inc. On July 19, 2002, we acquired QSI pursuant to an Agreement and Plan of Merger dated May 13, 2002, as amended, by and among Key, Key Merger Sub, Inc. and QSI. As consideration for the acquisition, we issued approximately 17.1 million shares of our common stock to the QSI shareholders and paid approximately $94.2 million in cash at the closing to retire debt and preferred stock of QSI and to satisfy certain other obligations of QSI. In addition to assuming the positive working capital of QSI, we incurred other direct acquisition costs and assumed certain other liabilities of QSI, resulting in us recording an aggregate purchase price of approximately $250 million. The value of the shares issued was based on the closing price of the our common stock on the closing date of $8.75 per share. The results of QSI's operations have been included in the consolidated financial statements since the closing date. Prior to the acquisition, QSI was a privately held corporation conducting field production, pressure pumping and other service operations in Louisiana, New Mexico, Oklahoma, Texas and the Gulf of Mexico. Both we and QSI operated in adjacent and/or overlapping locations and expect to realize future cost savings and synergies in connection with the merger. The combination of the companies formed one of the largest oilfield trucking fleets in the United States complementing our well service rig fleet, which based on the number of rigs owned and available industry data, is the largest in the world.

Other Acquisitions. During the Transition Period, we completed several small acquisitions for total consideration of $15,620,000, which consisted of a combination of cash, a deferred non-compete payment and shares of our common stock. Other than QSI, none of the other acquisitions completed in the Transition Period were material individually or in the aggregate, thus the pro forma effect of these acquisitions is not presented. Each of the acquisitions was accounted for using the purchase method and the results of the operations generated from the acquired assets are included in our results of operations as of the completion date of each acquisition.

New Senior Credit Facility

On July 15, 2002, we entered into a Third Amended and Restated Credit Agreement, as amended by the First Amendment to the Third Amended and Restated Credit Agreement (the "Senior Credit Facility"). The Senior Credit Facility consists of a $150,000,000 revolving loan facility with a $75,000,000 sublimit for letters of credit. The loans are secured by most of our tangible and intangible assets. The revolving loan commitment will terminate on July 15, 2005 and all revolving loans must be paid on or before that date. The revolving loans bear interest based upon, at our option, the prime rate plus a variable margin of 0.00% to 1.00% or a Eurodollar rate plus a variable margin of 1.75% to 3.00%. The Senior Credit Facility has customary affirmative and negative covenants including maximum leverage ratios, a minimum fixed charge coverage ratio and a minimum net worth, as well as limitations on liens and indebtedness and restrictions on dividends, acquisitions and dispositions.

Description of Business Segments

We operate in two primary business segments, which are well servicing and contract drilling. Our operations are conducted domestically and internationally in Argentina, Egypt and Canada. The following is a description of each of these business segments (for financial information regarding these business segments, see Note 13 to Consolidated Financial Statements Business Segment Information).

Well Servicing

We provide a full range of well services, including rig-based services, oilfield trucking services, well intervention services and other ancillary oilfield services necessary to maintain and workover oil and natural gas producing wells. Rig-based services include: maintenance of existing wells, workovers of existing wells, completion of newly drilled wells, recompletion of existing wells (including horizontal recompletions) and plugging and abandonment of wells at the end of their useful lives. Well intervention services include fishing and rental tool services and pressure pumping services.

Well Service Rigs

We use our well service rig fleet to perform four major categories of rig services for oil and natural gas producers.

Maintenance Services. We provide the well service rigs, equipment and crews for maintenance services, which are performed on both oil and natural gas wells, but which are more commonly required on oil wells. While some oil wells in the United States flow oil to the surface without mechanical assistance, most require pumping or some other method of artificial lift. Oil wells that require pumping characteristically require more maintenance than flowing wells due to the operation of the mechanical pumping equipment. Few natural gas wells have mechanical pumping systems in the wellbore, and, as a result, maintenance work on natural gas wells is less frequent.

Maintenance services are required throughout the life of most producing oil and natural gas wells to ensure efficient and continuous operation. These services consist of routine mechanical repairs necessary to maintain production from the well, such as repairing inoperable pumping equipment in an oil well or replacing defective tubing in an oil or natural gas well, and removing debris such as sand

and paraffin from the well. Other services include pulling the rods, tubing, pumps and other downhole equipment out of the wellbore to identify and repair a production problem.

Maintenance services are often performed on a series of wells in proximity to each other and typically require less than 48 hours per well to complete. The general demand for maintenance services is closely related to the total number of producing oil and natural gas wells in a geographic market, and maintenance services are generally the most stable type of well service activity.

Workover Services. In addition to periodic maintenance, producing oil and natural gas wells occasionally require major repairs or modifications, called "workovers." Workover services are performed to enhance the production of existing wells. Such services include extensions of existing wells to drain new formations either through deepening wellbores to new zones or by drilling horizontal lateral wellbores to improve reservoir drainage patterns. In less extensive workovers, our rigs are used to seal off depleted zones in existing wellbores and access previously bypassed productive zones. Our workover rigs are also used to convert former producing wells to injection wells through which water or carbon dioxide is pumped into the formation for enhanced recovery operations. Other workover services include: major subsurface repairs such as casing repair or replacement, recovery of tubing and removal of foreign objects in the wellbore, repairing downhole equipment failures, plugging back the bottom of a well to reduce the amount of water being produced with the oil and natural gas, cleaning out and recompleting a well if production has declined, and repairing leaks in the tubing and casing. These extensive workover operations are normally performed by a well service rig with a workover package, which may include rotary drilling equipment, mud pumps, mud tanks and blowout preventers depending upon the particular type of workover operation. Most of our well service rigs are designed for and can be equipped to perform complex workover operations.

Workover services are more complex and time consuming than routine maintenance operations and consequently may last from a few days to several weeks. These services are almost exclusively performed by well service rigs.

Completion Services. Our completion services prepare a newly drilled oil or natural gas well for production. The completion process may involve selectively perforating the well casing to access producing zones, stimulating and testing these zones and installing downhole equipment. We typically provide a well service rig and may also provide other equipment such as a workover package to assist in the completion process. Producers use well service rigs to complete their wells because the rigs have specialized equipment, properly trained employees and the experience necessary to perform these services. However, during periods of weak drilling rig demand, drilling contractors may compete with service rigs for completion work.

The completion process typically requires a few days to several weeks, depending on the nature and type of the completion, and generally requires additional auxiliary equipment that can be provided for an additional fee. The demand for well completion services is directly related to drilling activity levels, which are highly sensitive to expectations relating to, and changes in, oil and natural gas prices. As the number of newly drilled wells decreases, the number of completion jobs correspondingly decreases.

Plugging and Abandonment Services. Well service rigs and workover equipment are also used in the process of permanently closing oil and natural gas wells at the end of their productive lives. Plugging and abandonment work can be performed with a well servicing rig along with wireline and cementing equipment. The services generally include the sale or disposal of equipment salvaged from the well as part of the compensation received and require compliance with state regulatory requirements. The demand for oil and natural gas does not significantly affect the demand for plugging and abandonment services, as well operators are required by state regulations to plug a well that is no longer productive. The need for these services is also driven by lease and/or operator policy requirements.

Oilfield Trucking

Upon completion of the acquisition of QSI, we had substantially expanded our liquid/vacuum truck services and fluid transportation and disposal services for operators whose wells produce saltwater and other fluids, in addition to oil and natural gas. Of the approximately 2,295 heavy oilfield service vehicles operated by us following the acquisition of QSI, we operate approximately 1,026 vacuum and transport trucks in the United States. In addition, we own approximately 2,968 frac tanks which are used in conjunction with our fluid hauling operations.

Fluid hauling trucks are utilized in connection with drilling and workover projects, which tend to produce and use large amounts of various oilfield fluids. Fluid hauling companies transport fresh water to the well site and provide temporary storage and disposal of produced salt water and drilling/workover fluids. These fluids are picked up at the well site and transported for disposal in a salt water disposal well of which we own approximately 130. In addition, we provide haul/equipment trucks that are used to move large pieces of equipment from one wellsite to the next and operate a fleet of approximately 132 hot oilers, which are capable of heating pumped fluids that may be used to clear restrictions in a wellbore such as paraffin build-up. Demand and pricing for these services are generally related to demand for our well service and drilling rigs. Fluid hauling and equipment hauling services are typically priced on a per hour basis while frac tank rentals are typically billed on a per day basis.

Well Intervention Services

Through our acquisition of QSI in July 2002, we significantly expanded our fishing and rental tool operations and added a pressure pumping business.

Fishing and Rental Tool Services. Founded in 1993, QSI's fishing and rental tool operation, Quality Tubular Services, Inc. ("QTS"), provides fishing and rental tool services to major and independent oil and natural gas production companies primarily in the Gulf Coast region of the United States. Fishing services involve recovering downhole equipment that has been lost or become trapped in the wellbore and a "fishing tool" is a tool specifically designed to recover that equipment lost or trapped in the well. QTS operates nine 24-hour service locations and four regional sales offices. The fishing tool supervisors have extensive experience with downhole problems. In addition, QTS offers a full line of services and equipment designed for the harsh elements from land to offshore. The rental tool inventory consists of tubulars, handling tools, pressure-control equipment and a fleet of power swivels. Key also provides fishing and rental tools through our Landmark Fishing and Rental Tools operation in the Mid-Continent region and at various other locations throughout the country.

Pressure Pumping Services. Our pressure pumping business operates under the name American Energy Services ("AES"). AES provides stimulation services, cementing services, nitrogen services, hydro-testing and production chemistry services to oil and natural gas producers. We offer a full complement of acidizing technology, fracturing technology, nitrogen technology and cementing technology services. AES was established in December 1996 and operates in the Permian Basin, the San Juan Basin, and the Mid-Continent Region.

Ancillary Oilfield Services

We provide ancillary oilfield services, which includes: wireline operations (lowering mechanical and electrical tools in the well); well site construction (preparation of a wellsite for drilling activities); roustabout services (coordination of equipment and supplies from an offshore rig to the shore base); foam units (drilling technique using air or gas to which a foaming agent has been added); and air

drilling services (drilling technique using compressed air). Demand and pricing for these services are generally related to demand for our well service and drilling rigs.

Contract Drilling

We provide contract drilling services to major oil companies and independent oil and natural gas producers onshore the continental United States in the Permian Basin, the Four Corners region, Michigan, the Northeast, and the Rocky Mountains and internationally in Argentina and Canada (Ontario). Contract drilling services are primarily provided under standard dayrate, and, to a lesser extent, footage or turnkey contracts. Drilling rigs vary in size and capability and may include specialized equipment. The majority of our drilling rigs are equipped with mechanical power systems and have depth ratings ranging from approximately 4,500 to 12,000 feet. We have one drilling rig with a depth rating of approximately 18,000 feet. Like workover services, the demand for contract drilling is directly related to expectations relating to, and changes in, oil and natural gas prices which in turn, are driven by the supply of and demand for these commodities.

Foreign Operations

We also operate each of our business segments discussed above in Argentina, Canada (Ontario) and Egypt. Our foreign operations currently own approximately 25 well servicing rigs, 75 oilfield trucks and seven drilling rigs in Argentina, four well servicing rigs, four oilfield trucks and two drilling rigs in Ontario, Canada and five well servicing rigs and 10 oilfield trucks in the Arab Republic of Egypt.

Customers

Our customers include major oil companies, independent oil and natural gas production companies, and foreign national oil and natural gas production companies. One customer in the year ended June 30, 2002, Occidental Petroleum Corporation, accounted for approximately 10% of our consolidated revenues. No single customer in the six months ended December 31, 2002 accounted for 10% or more of our consolidated revenues.

Competition and Other External Factors

Despite the significant consolidation that has occurred in the domestic well servicing industry, there are numerous smaller companies that compete in our well servicing markets. Nonetheless, we believe that our performance, equipment, safety, and availability of equipment to meet customer needs and availability of experienced, skilled personnel is superior to that of our competitors.

In the well servicing markets, an important competitive factor in establishing and maintaining long-term customer relationships is having an experienced, skilled and well-trained work force. In recent years, many of our larger customers have placed increased emphasis on the safety records and quality of the crews, equipment and services provided by their contractors. We have, and will continue to devote substantial resources toward employee safety and training programs. Management believes that many of our competitors, particularly small contractors, have not undertaken similar training programs for their employees. Management believes that our safety record and reputation for quality equipment and service are among the best in the industry.

In the contract drilling market, we compete with other regional and national oil and natural gas drilling contractors, some of which have larger rig fleets with greater average depth capabilities and a few that have better capital resources than us. Management believes that the contract drilling industry is less consolidated than the well servicing industry, resulting in a contract drilling market that is more price competitive. Nonetheless, we believe that we are competitive in terms of drilling performance, equipment, safety, pricing, availability of equipment to meet customer needs and availability of experienced, skilled personnel in those regions in which we operate.

The need for well servicing and contract drilling fluctuates, primarily, in relation to expectations relating to, and fluctuations in, the price of oil and natural gas which, in turn, is driven by the supply of and demand for oil and natural gas. As supply of those commodities decreases and demand increases, service and maintenance requirements tend to eventually increase as oil and natural gas producers attempt to maximize the producing efficiency of their wells in a higher priced environment.

Employees

As of December 31, 2002, we employed approximately 8,409 persons (approximately 8,287 employees in our well servicing and contract drilling businesses and approximately 122 employees on our corporate staff). Our employees are not represented by a labor union and are not covered by collective bargaining agreements. We have not experienced work stoppages associated with labor disputes or grievances and considers its relations with our employees to be satisfactory.

Environmental Regulations

Our operations are subject to various local, state and federal laws and regulations intended to protect the environment. Our operations routinely involve the handling of waste materials, some of which are classified as hazardous substances. Consequently, the regulations applicable to our operations include those with respect to containment, disposal and controlling the discharge of any hazardous oilfield waste and other non-hazardous waste material into the environment, requiring removal and cleanup under certain circumstances, or otherwise relating to the protection of the environment. Laws and regulations protecting the environment have become more stringent in recent years, and may in certain circumstances impose "strict liability," rendering a party liable for environmental damage without regard to negligence or fault on the part of such party. Such laws and regulations may expose us to liability for the conduct of, or conditions caused by, others, or for our acts, which were in compliance with all applicable laws at the times such acts were performed. Cleanup costs and other damages arising as a result of environmental laws, and costs associated with changes in environmental laws and regulations could be substantial and could have a material adverse effect on our financial condition. From time to time, claims have been made and litigation has been brought against us under such laws. However, the uninsured costs incurred in connection with such claims and other costs of environmental compliance have not had any material adverse effect on our operations or financial statements in the past, and management is not currently aware of any situation or condition that it believes is likely to have any such material adverse effect in the future. Management believes that it conducts our operations in substantial compliance with all material federal, state and local regulations as they relate to the environment. Although we have incurred certain costs in complying with environmental laws and regulations, such amounts have not been material to our financial results during the past three and one half years.

MANAGEMENT

Directors And Executive Officers

The following table sets forth the names and ages, as of April 30, 2003, of each of our executive officers and directors and includes their current positions.

Name	Age	Position
Francis D. John	49	Chairman of the Board, President, and Chief Executive Officer
David J. Breazzano	46	Director
Ralph S. Michael, III	48	Director
Kevin P. Collins	52	Director
William D. Fertig	46	Director
J. Robinson West	56	Director
W. Phillip Marcum	59	Director
Morton Wolkowitz	74	Director
James J. Byerlotzer	56	Executive Vice President and Chief Operating Officer
Royce Mitchell	48	Executive Vice President, Chief Financial Officer and Chief Accounting Officer

Francis D. John has been (i) the President and a director since June 1988, (ii) the Chief Executive Officer since October 1989 and (iii) the Chairman of the Board since August 1996. In addition, he served as the Chief Financial Officer from October 1989 through July 1997 and as Chief Operating Officer from April 1999 through December 2001. Before joining the Company, he was Executive Vice President of Finance and Manufacturing of Fresenius U.S.A., Inc. Mr. John previously held operational and financial positions with Unisys, Mack Trucks and Arthur Andersen. He received a BS from Seton Hall University and an MBA from Fairleigh Dickinson University.

David J. Breazzano has been a director since October 1997. Mr. Breazzano is one of the founding principals at DDJ Capital Management, LLC, an investment management firm established in 1996. Mr. Breazzano previously served as a Vice President and Portfolio Manager at Fidelity Investments from 1990 to 1996. Prior to joining Fidelity Investments, Mr. Breazzano was President and Chief Investment Officer of the T. Rowe Price Recovery Fund. He is also a director of North East Waste Services, Inc. and Samuels Jewelers, Inc. He holds a BA from Union College and an MBA from Cornell University.

Kevin P. Collins has been a director since March 1996. Mr. Collins has been a managing member of the Old Hill Company LLC since 1997. From 1992 to 1997, he served as a principal of JHP Enterprises, Ltd., and from 1985 to 1992, as Senior Vice President of DG Investment Bank, Ltd., both of which were engaged in providing corporate finance and advisory services. Mr. Collins was a director of WellTech, Inc. from January 1994 until March 1996 when WellTech, Inc. was merged into the Company. Mr. Collins is also a director of The Penn Traffic Company, Metretek Technologies, Inc., and London Fog Industries, Inc. Mr. Collins is a Chartered Financial Analyst and holds a BS and an MBA from the University of Minnesota.

William D. Fertig has been a director since April 2000. Mr. Fertig is Co-Chairman and Chief Investment Officer of Context Capital Management, an investment advisory firm. Mr. Fertig was previously a Principal and a Senior Managing Director of McMahan Securities from 1990 through April 2002. Mr. Fertig previously served as a Senior Vice President and Manager of Convertibles at Drexel Burnham Lambert prior to joining McMahan Securities in 1990, and from 1979 to 1989, served as Vice President and Convertible Securities Sales Manager at Credit Suisse First Boston. He holds a BS from Allegheny College and an MBA from New York University's Stern Business School.

W. Phillip Marcum has been a director since March 1996. Mr. Marcum was a director of WellTech, Inc. from January 1994 until March 1996 when WellTech, Inc. was merged into the Company. From October 1995 until March 1996, Mr. Marcum was the acting Chairman of the Board of Directors of WellTech, Inc. He has been Chairman of the Board, President and Chief Executive Officer of Metretek Technologies, Inc., since January 1991 and is a director of Contour Energy Co. He holds a BBA from Texas Tech University.

Ralph S. Michael, III has been a director since March 2003. From February 2001 to September 2002, he served as Executive Vice President and Group Executive of PNC Financial Services Group, with responsibility for PNC Advisors, PNC Capital Markets and PNC Leasing. From March 1996 to February 2001, he served as Executive Vice President and Chief Executive Officer of PNC Corporate Banking. He served as President of PNC Bank, Ohio from May 1992 to March 1996, and as Chief Executive Officer from August 1992 to March 1996. He served as Executive Vice President of Pittsburgh National Bank from March 1991 to May 1992, and served in a number of management positions with Pittsburgh National Bank since his hire in 1979. He has been a director of Ohio Casualty Corporation, a property and casualty insurance business, since April 2002. He has also been a director of T.H.E. Inc. since 1991. He holds a BA from Stanford University and an MBA from the UCLA Graduate School of Management.

J. Robinson West has been a director since November 2001. Mr. West is the founder, and has served as Chairman and a director of the PFC Energy, strategic advisers to international oil and gas companies, national oil companies, and petroleum ministries, since 1984. Previously, Mr. West served as U.S. Assistant Secretary of the Interior with responsibility for offshore oil leasing policy from 1981 through 1983. He was Deputy Assistant Secretary of Defense for International Economic Affairs from 1976 through 1977 and a member of the White House Staff from 1974 through 1976. He is currently on the Secretary of Energy Advisory Board and is also a member of the Council on Foreign Relations. He holds a BA with advanced standing from the University of North Carolina at Chapel Hill and a JD from Temple University.

Morton Wolkowitz has been a director since December 1989. Mr. Wolkowitz served as President and Chief Executive Officer of Wolkow Braker Roofing Corporation, a privately held company that provided a variety of roofing services, from 1958 through 1989. Mr. Wolkowitz has been a private investor since 1989. He holds a BS from Syracuse University.

James J. Byerlotzer, 56, was elected Executive Vice President and Chief Operating Officer effective January 2002. Mr. Byerlotzer served as Executive Vice President of Domestic Well Service and Drilling Operations from July 1999 through December 1999 and Executive Vice President of Domestic Operations from December 1999 through December 2001. He joined the Company in September 1998 as Vice President Permian Basin Operations after the Company's acquisition of Dawson Production Services, Inc. From February 1997 to September 1998, he served as the Senior Vice President and Chief Operating Officer of Dawson Production Services, Inc. From 1981 to 1997, Mr. Byerlotzer was employed by Pride Petroleum Services, Inc. Beginning in February 1996, Mr. Byerlotzer served as the Vice President Domestic Operations of Pride Petroleum Services, Inc. Prior to that time, he served as Vice President Permian Basin of Pride Petroleum Services, Inc. and in various other operating positions in its Gulf Coast and California operations. Mr. Byerlotzer holds a BA from the University of Missouri in St. Louis.

Royce W. Mitchell, 48, was elected Executive Vice President, Chief Financial Officer and Chief Accounting Officer effective January 2002. Before joining the Company, he was a partner with KPMG LLP from April 1986 through December 2001 specializing in the oil and gas industry. He received a BBA from Texas Tech University and is a certified public accountant.

Directors are elected at the Company's annual meeting of stockholders and serve until the next annual meeting of stockholders and until their successors are elected and qualified. Each executive officer holds office until the first meeting of the Board of Directors following the annual meeting of stockholders and until his successor has been duly elected and qualified.

Director Compensation

No director who is also employed by us or any of our subsidiaries received any fees from us for his services as a director or as a member of any committee of the Board. During the fiscal year ended June 30, 2002 and the six-month transition period ended December 31, 2002, each non-employee director received a fee of $3,000 per month for each month of service and were reimbursed for travel and other expenses directly associated with Company business. Effective April 1, 2003, in connection with the increased obligations placed on the members of the Board of Directors resulting from the implementation of the Sarbanes-Oxley Act of 2002 and other corporate governance initiatives, and in order to retain and attract qualified candidates to serve on the Board of Directors, the Board increased director fees to (i) $80,000 per year for the Audit Committee Chairman and (ii) $65,000 per year for all other outside directors. Additionally, during the fiscal year ended June 30, 2002, we paid the annual premiums on life insurance policies for the benefit of Messrs. Collins and Marcum in the amount of $2,906 and $5,390, respectively.

For the six-month transition period ended December 31, 2002, we paid the annual premiums on life insurance policies for the benefit of Messrs. Collins and Marcum in the amount of $2,906 and $5,390, respectively. These policies currently have cash surrender values of $12,048 and $16,852, for Messrs. Marcum and Collins, respectively. Effective January 1, 2003, we ceased paying the premiums due with respect to these policies.

Executive Compensation

Summary Compensation Table. The following table reflects the compensation for services to the Company for the fiscal years ended June 30, 2002, 2001 and 2000, and for the six-month transition period ended December 31, 2002 for (i) the Chief Executive Officer of the Company, (ii) the other executive officers of the Company other than the Chief Executive Officer who were serving as executive officers at June 30, 2002 and December 31, 2002, and (iii) a former executive officer of the Company for whom disclosure would have been made but for the fact that such individual was not serving as an

executive officer of the Company at June 30, 2002 or at December 31, 2002 (collectively, the "Named Executive Officers").

	Annual Compensation				Long-Term Compensation Awards	
Name and Principal Position	**Fiscal Year(1)**	**Salary ($)**	**Bonus ($)**	**Other Annual Compensation ($)**	**Shares Underlying Options(2)**	**All Other Compensation ($)**
Francis D. John	2002(3)	297,635				
President and Chief Executive	2002	595,000	300,000	105,972(4)	400,000	13,209,658(5)
Officer	2001	594,885	845,000	71,116(6)	1,460,000	74,998(7)
	2000	589,515	307,776		2,000,000	
James J. Byerlotzer	2002(3)	170,520				
Executive Vice President and	2002	250,000	140,000		150,000	35,615(8)
Chief Operating Officer	2001	249,324	275,000		115,000	101,000(9)
	2000	185,000	89,000		300,000	100,250(10)
Royce W. Mitchell	2002(3)	153,635		35,666(12)		
Executive Vice President and	2002	140,692			200,000	100,000(13)
Chief Financial Officer(11)	2001					
	2000					
Thomas K. Grundman	2002(3)					
Executive Vice President M&A	2002	247,691	150,000		150,000	140,020(15)
and International(14)	2001	274,966	315,000		135,000	78,519(16)
	2000	203,845	100,000		500,000	24,975(17)

(1) Change in fiscal year end. In December 2002, the Company changed its fiscal year end from June 30 to December 31. As a result, the Company is providing summary compensation information for the six-month transition period ended December 31, 2002 in addition to the twelve-month periods ended June 30, 2002, June 30, 2001 and June 30, 2000.

Summary compensation information for Mr. John, the Company's President and Chief Executive Officer, for calendar 2002, 2001 and 2000 is provided below:

	Annual Compensation				Long-Term Compensation Awards	
Name and Principal Position	**Calendar Year(1)**	**Salary ($)**	**Bonus ($)**	**Other Annual Compensation ($)(a)**	**Shares Underlying Options(b)**	**All Other Compensation ($)(c)**
Francis D. John	2002	595,270	0	76,049	0	51,639
	2001	595,000	857,500	75,150	400,000	13,161,283(d)

		Annual Compensation			Long-Term Compensation Awards	
	2000	584,885	595,276		3,460,000	71,734

(a)
Represents reimbursement of medical expenses, professional fees, personal use of a company-provided vehicle and other miscellaneous expenses.

(b)
See Note 2.

(c)
Represents life and health insurance premium payments made by the Company and contributions made by the Company to Mr. John's company-sponsored 401(k) account.

(d)
Includes a ten-year incentive retention payment made in calendar 2001 in connection with the conversion of a previously approved and previously earned performance-based incentive loan program, of which Mr. John earned $1.3 million during the fiscal year ended June 30, 2002 (for more information on the incentive retention payment, see "Management Employment Agreements with Executive Officers" and "Certain Relationships and Related Transactions").

(2)
Represents the number of shares issuable pursuant to vested and non-vested stock options granted during the applicable fiscal year.

(3)
Represents the six-month transition period ended December 31, 2002 (See Note 1).

(4)
Represents reimbursement of (i) medical expenses of $24,502, (ii) professional fees of $44,470, and (iii) other miscellaneous personal expenses of $25,000. The remaining $12,000 represents the Company's estimate of the value of Mr. John's use of a company-provided vehicle for personal business.

(5)
Represents (i) $128,996 in premiums paid by the Company for health insurance and life insurance (cash surrender value of the life insurance policy is $28,077) and (ii) $1,000 in contributions made by the Company on behalf of Mr. John to the Key Energy Services, Inc. 401(k) Savings and Retirement Plan. The remaining amount represents a ten-year incentive retention payment made in calendar 2001 in connection with the conversion of a previously approved and previously earned performance-based incentive loan program, of which Mr. John earned $1.3 million during the fiscal year ended June 30, 2002 (for more information on the incentive retention payment, see "Management Employment Agreements with Executive Officers" and "Certain Relationships and Related Transactions").

(6)
Represents reimbursement of (i) medical expenses of $12,186, (ii) professional fees of $48,930, and (iii) other miscellaneous expenses of $10,000.

(7)
Represents premium payments by the Company for life and health insurance.

(8)
Represents (i) payments to Mr. Byerlotzer pursuant to a non-competition agreement entered into in connection with the Company's acquisition of Dawson Production Services, Inc. of $34,615, and (ii) contributions by the Company on behalf of Mr. Byerlotzer to the Key Energy Services, Inc. 401(k) Savings and Retirement Plan of $1,000.

(9)
Represents (i) payments to Mr. Byerlotzer pursuant to a non-competition agreement entered into in connection with the Company's acquisition of Dawson Production Services, Inc. of $100,000, and (ii) contributions by the Company on behalf of Mr. Byerlotzer to the

Key Energy Services, Inc. 401(k) Savings and Retirement Plan of $1,000.

(10)
Represents (i) payment to Mr. Byerlotzer pursuant to a non-competition agreement entered into in connection with the Company's acquisition of Dawson Production Services, Inc. of $100,000 and (ii) contributions by the Company on behalf of Mr. Byerlotzer to the Key Energy Services, Inc. 401(k) Savings and Retirement Plan of $250.

(11)
Mr. Mitchell joined the Company as an executive officer effective January 1, 2002.

(12)
Represents payment of certain costs incurred by Mr. Mitchell in connection with his relocation from Dallas, Texas to Midland, Texas as a result of Mr. Mitchell joining the Company.

(13)
Represents a one-time signing bonus that is subject to repayment if Mr. Mitchell's employment with the Company is terminated by Mr. Mitchell voluntarily or by the Company for cause (see "Management Employment Agreements with Executive Officers").

(14)
Mr. Grundman ceased serving as an executive officer and left the employment of the Company effective May 6, 2002.

(15)
Represents (i) forgiveness of relocation loan indebtedness and interest to Mr. Grundman of $114,295 (pursuant to a relocation loan forgiveness program that was implemented in July 1999 in connection with Mr. Grundman's hiring), (ii) premium payments made by the Company for life insurance of $24,725 and (iii) contributions by the Company on behalf of Mr. Grundman to the Key Energy Services, Inc. 401(k) Savings and Retirement Plan of $1,000.

(16)
Represents (i) forgiveness of relocation loan indebtedness and interest to Mr. Grundman of $52,794 (pursuant to a relocation loan forgiveness program that was implemented in July 1999 in connection with Mr. Grundman's hiring), (ii) premium payments made by the Company for life insurance of $24,725 and (iii) contributions by the Company on behalf of Mr. Grundman to the Key Energy Services, Inc. 401(k) Savings and Retirement Plan of $1,000.

(17)
Represents (i) premium payments by the Company for life insurance of $24,725 and (ii) contributions by the Company on behalf of Mr. Grundman to the Key Energy Services, Inc. 401(k) Savings and Retirement Plan of $250.

Option Grants in Fiscal Year Ended June 30, 2002 and in Six-Month Transition Period Ended December 31, 2002

The following table sets forth certain information relating to options granted under the Key Energy Group, Inc. 1997 Incentive Plan (the "Plan") and outside the Plan to the Named Executive Officers during the fiscal year ended June 30, 2002 and the six-month transition period ended December 31, 2002. The Company did not grant any stock appreciation rights to the Named Executive Officers during the fiscal year ended June 30, 2002 or the six-month transition period ended December 31, 2002.

Name	Fiscal Year (1)	Number of Securities Underlying Options Granted Employees in Fiscal Year	Percentage of Total Options Granted Employees in Fiscal Year(2)	Exercise Price Per Share	Expiration Date	Grant Present Value(3)
Francis D. John	2002(4)	0	0%			
	2002	400,000(5)	20.1%	$ 8.00	10/16/11	$ 1,519,287
Royce W. Mitchell	2002(4)	0	0%			
	2002	200,000(6)	10.1%	$ 8.90	01/03/12	845,103
James J. Byerlotzer	2002(4)	0	0%			
	2002	150,000(7)	7.5%	$ 8.00	10/16/11	569,733

Name	Fiscal Year (1)	Number of Securities Underlying Options Granted Employees in Fiscal Year	Percentage of Total Options Granted Employees in Fiscal Year(2)	Exercise Price Per Share	Expiration Date	Grant Present Value(3)
Thomas K. Grundman(8)	2002(4)	0				
	2002	150,000(9)	7.5%	$ 8.00	10/16/11(9)	569,733

(1) Change in fiscal year end. In December 2002, the Company changed its fiscal year end from June 30 to December 31. As a result, the Company is providing information concerning option grants for the six-month transition period ended December 31, 2002 in addition to the twelve-month period ended June 30, 2002.

(2) Based on (i) options to purchase a total of 1,988,000 shares of Common Stock granted during fiscal year ended June 30, 2002, and (ii) options to purchase a total of 182,500 shares of Common Stock granted during the six-month transition period ended December 31, 2002.

(3) The grant date value of stock options granted during the fiscal year ended June 30, 2002 was estimated using the Black-Scholes option pricing model with the following assumptions: expected volatility 50%; risk-free interest rate 3.35%; time of exercise 5 years; and no dividend yield.

(4) Represents the six-month transition period ended December 31, 2002 (see Note 1).

(5) These options were granted on October 16, 2001 and vest as follows: 133,333 on July 1, 2002; 133,333 on July 1, 2003; and 133,334 on July 1, 2004.

(6) These options were granted on January 3, 2002 and vest as follows: 50,000 on January 3, 2002; 50,000 on January 3, 2003; 50,000 on January 3, 2004; and 50,000 on January 3, 2005.

(7) These options were granted on October 16, 2001 and vest as follows: 50,000 on July 1, 2002; 50,000 on July 1, 2003; and 50,000 on July 1, 2004.

(8) Mr. Grundman was not employed by the Company during the six-month transition period ended December 21, 2002.

(9) These options were granted on October 16, 2001 and originally vested as follows: 50,000 on July 1, 2002; 50,000 on July 1, 2003; and 50,000 on July 1, 2004. In connection with Mr. Grundman's separation from the Company effective May 6, 2002, these options became immediately vested and will remain exercisable for a period of three years following his termination date (see "Management Severance Agreement").

Aggregated Option Exercises and Values as of Fiscal Year Ended June 30, 2002

The following table sets forth certain information as of June 30, 2002 relating to the number and value of unexercised options held by the Named Executive Officers. None of the Named Executive Officers exercised stock options during fiscal year ended June 30, 2002.

Name	Number of Unexercised Options at June 30, 2002		Value of Unexercised In-the-Money Options at June 30, 2002(1)	
	Exercisable	Unexercisable	Exercisable	Unexercisable
Francis D. John	2,710,000	900,000	$ 4,977,707	$ 1,854,168
Royce W. Mitchell	50,000	150,000	80,000	240,000
James J. Byerlotzer	241,667	418,333	745,004	1,159,995
Thomas K. Grundman(2)	885,000	0	2,428,750	0

(1) The dollar values in these columns are calculated by determining the difference between the fair market value of the Common Stock for which the relevant options are exercisable as of June 30, 2002 and the exercise price of the options. The fair market value is based on the last sale price of the Common Stock on the NYSE on June 28, 2002, which was $10.50.

(2) In connection with Mr. Grundman's separation from the Company effective May 6, 2002, all options that were not vested as of that date became immediately vested and exercisable on that date (see "Management Severance Agreement").

Aggregated Option Exercises and Values as of Six-Month Transition Period Ended December 31, 2002

The following table sets forth certain information as of December 31, 2002 relating to the number and value of unexercised options held by the Named Executive Officers. Mr. Grundman, who was not employed by the Company during the six-month transition period ended December 31, 2002, exercised

100,000 options on August 2, 2002. None of the other Named Executive Officers exercised stock options during the six-month transition period ended December 31, 2002.

Name	Shares Acquired on Exercise	Value Realized(1)	Number of Unexercised Options at December 31, 2002		Value of Unexercised In-the-Money Options at December 31, 2002(2)	
			Exercisable	Unexercisable	Exercisable	Unexercisable
Francis D. John			2,843,332	766,668	$ 1,505,325	$ 418,500
Royce W. Mitchell			50,000	150,000	3,500	10,500
James J. Byerlotzer			371,666	288,334	700,100	195,100
Thomas K. Grundman	100,000	$ 472,000	785,000	0	477,700	0

(1) The dollar value in this column is calculated by determining the difference between the fair market value of the Common Stock on the date of exercise of the relevant options and the exercise price of such options. The fair market value on the date of exercise is based on the last sale price of the Common Stock on the NYSE on such date, which was $7.72.

(2) The dollar values in these columns are calculated by determining the difference between the fair market value of the Common Stock for which the relevant options are exercisable as of December 31, 2002 and the exercise price of such options. The fair market value is based on the last sale price of the Common Stock on the NYSE on December 31, 2002, which was $8.97.

Employment Agreements With Executive Officers

Francis D. John. Effective as of July 1, 2001, we entered into an amended and restated employment agreement with Mr. John, which provides that Mr. John will serve as our Chairman of the Board, President and Chief Executive Officer for a five-year term commencing July 1, 2001 and continuing until June 30, 2006, with an automatic one-year renewal on each June 30, commencing on June 30, 2006, unless terminated by us or by Mr. John with proper notice. The employment agreement contains a comprehensive non-compete provision that prohibits Mr. John from engaging in any activities that are competitive with us for a period of three years after the termination of his employment.

Mr. John currently receives an annual base compensation of $695,000, subject to increase after annual reviews by the Board of Directors. In addition to an annual base salary, the employment agreement provides for the following components of compensation: (i) periodic cash bonuses made pursuant to our Performance Compensation Plan based on performance criteria approved by the Compensation Committee and other discretionary cash bonuses made to reward extraordinary accomplishments and actions by us or Mr. John, (ii) stock option grants, some of which vest over several years and some of which vest subject to meeting certain performance criteria and (iii) a significant repayment obligation triggered if Mr. John leaves voluntarily or is terminated for cause (see discussion below).

In addition to salary and bonus, Mr. John is entitled to medical, dental, accident and life insurance, reimbursement of expenses and certain other benefits. To the extent Mr. John is taxed on any such reimbursement or benefit, we will pay Mr. John an amount which, on an after-tax basis, equals the amount of these taxes.

In the event that Mr. John's employment is terminated (1) by us voluntarily or by nonrenewal, (2) by Mr. John for "Good Reason," (3) by either us or Mr. John following a "Change in Control" (in

each case as defined in the employment agreement), or (4) as a result of Mr. John's disability, Mr. John will be entitled to receive:

(i) his accrued but unpaid salary and bonuses to the date of termination, and a pro rata bonus for the year in which termination occurs;

(ii) a severance payment in an amount equal to three times his average total annual compensation (i.e., salary plus bonus) for the preceding three years (except that in the case of termination as a result of Mr. John's disability, such compensation will be reduced by the amount of any Company-paid disability insurance proceeds paid to Mr. John);

(iii) immediately vesting and exercisability of all stock options held by him (to the extent not already vested and exercisable) for the remainder of the original terms of the options;

(iv) any other amounts or benefits earned, accruing or owing to him, but not yet paid; and

(v) continued participation in medical, dental and life insurance coverage, as well as the receipt of other benefits to which he was entitled, until the first to occur of the third year anniversary of the date his employment was terminated or the date on which he received equivalent coverage and benefits under the plans and programs of a subsequent employer (or, in the event of a "Change of Control," an amount in cash equal to the reasonable expenses that we would incur if we were to provide these benefits for three years).

In the event that Mr. John's employment is terminated by us for "Cause," as defined in his employment agreement, or by Mr. John voluntarily or by nonrenewal, he will be entitled to receive only the benefits described under clauses (i) and (iv) above and will forfeit any restricted stock or options not previously vested. In the event Mr. John's employment is terminated by reason of his death, he will be entitled to receive the benefits described under clauses (i), (iii), (iv) and (v) above, except that his family will be entitled to receive the medical and dental insurance coverage provided in clause (v) above until the death of Mr. John's spouse. In addition, if any of the above benefits are subject to the tax imposed by Section 4999 of the Internal Revenue Code, we will reimburse Mr. John for such tax on an after-tax basis.

Pursuant to the employment agreement, we made a one-time retention incentive payment to Mr. John equal to the aggregate amount of all principal and interest on loans previously made by us to Mr. John that were to be forgiven over a ten-year period beginning July 1, 2001, as well as the amount, on an after-tax basis, required to pay the taxes incurred Mr. John in connection with such payment. The after-tax proceeds of the retention incentive payment were used to repay the outstanding principal and interest on the loans. *Mr. John did not receive any net proceeds from the payment*. The employment agreement provides that if, prior to June 30, 2011, Mr. John is terminated by us for Cause, or by Mr. John voluntarily or by nonrenewal, Mr. John will repay to us a percentage of the retention incentive payment beginning at 100% during the first year and declining at the rate of 10% each year to 0% on and after June 30, 2011. (For more information on the incentive retention payment, see

"Certain Relationships and Related Transactions").

James J. Byerlotzer. Effective as of June 1, 2002, Mr. Byerlotzer entered into an employment agreement with us pursuant to which he serves as our Executive Vice President and Chief Operating Officer. This agreement is for a two and one-half year term and thereafter for successive one-year terms unless terminated 90 days prior to the commencement of an extension term. Mr. Byerlotzer currently receives annual base compensation of $340,000, which can be increased but not decreased. Mr. Byerlotzer is eligible for additional annual incentive bonuses. If during the term of his employment agreement Mr. Byerlotzer is terminated by us for any reason other than for cause, or if he terminates his employment because of a material breach by us or following a change of control of the Company, he will be entitled to severance compensation equal to three times his annual base compensation in effect at the time of termination payable in equal installments over a 36-month period following termination; provided, however, that if termination results from a change of control of the Company, his severance compensation will be increased by an amount equal to three times the average annual bonus received by Mr. Byerlotzer over the preceding three years and will be payable in a lump sum on the date of termination. Also, if Mr. Byerlotzer is subject to the tax imposed by Section 4999 of the Internal Revenue Code, we have agreed to reimburse him for such tax on an after-tax basis.

Royce W. Mitchell. Effective as of January 1, 2002, Mr. Mitchell entered into an employment agreement with us pursuant to which he serves as our Executive Vice President and Chief Financial Officer. This agreement is for a three-year term and thereafter for successive one-year terms unless terminated 90 days prior to the commencement of an extension term. Mr. Mitchell currently receives an annual base compensation of $337,000, which can be increased but not decreased. Mr. Mitchell is eligible for additional annual incentive bonuses. In addition, Mr. Mitchell received a one-time signing bonus of $100,000. In the event that, prior to January 1, 2005, Mr. Mitchell is terminated by us for cause, or by Mr. Mitchell voluntarily, Mr. Mitchell will repay to us a percentage of the signing bonus beginning at 100% during the first year and declining at the rate of $^1/_3$ each year to 0% on and after January 1, 2005. If, during the term of his employment agreement, Mr. Mitchell is terminated by us for any reason other than for cause, or if he terminates his employment because of a material breach by us or following a change of control of the Company, he will be entitled to severance compensation equal to three times his annual base compensation in effect at the time of termination payable in equal installments over a 36-month period following termination; provided, however, that if termination results from a change of control of the Company, severance compensation will be increased by an amount equal to three times the average annual bonus received by Mr. Mitchell over the preceding three years and will be payable in a lump sum on the date of termination. Also, if Mr. Mitchell is subject to the tax imposed by Section 4999 of the Internal Revenue Code, we have agreed to reimburse him for such tax on an after-tax basis.

Jim D. Flynt. Effective as of April 1, 1999, Mr. Flynt entered into an employment agreement with us pursuant to which he then served as the President of our California Division. Effective March 5, 2003, Mr. Flynt became an executive officer when he was promoted to Senior Vice President Production Services. This agreement is for a three-year term and thereafter for successive one-year

terms unless terminated 30 days prior to the commencement of an extension term. Mr. Flynt currently receives an annual base compensation of $234,600, which can be increased but not decreased. Mr. Flynt is eligible for additional annual incentive bonuses. If during the term of his employment agreement, Mr. Flynt is terminated by us for any reason other than for cause, he will be entitled to severance compensation equal to one times his annual base compensation in effect at the time of termination payable in equal installments over a 12-month period following termination; provided, however, that in the event his employment should be terminated by us other than for cause within six months following a change of control of the Company, or in anticipation of a change of control of the Company, severance compensation will be payable in a lump sum on the date of termination.

Steven A. Richards. Effective as of February 5, 2001, Mr. Richards entered into an employment agreement with us pursuant to which he then served as our Vice President of Drilling Operations. Effective March 5, 2003, Mr. Richards became an executive officer when he was promoted to Senior Vice President Drilling and International. This agreement is for a two-year term and thereafter for successive one-year terms unless terminated 30 days prior to the commencement of an extension term. Mr. Richards currently receives an annual base compensation of $209,600, which can be increased but not decreased. Mr. Richards is eligible for additional annual incentive bonuses. If during the term of his employment agreement, Mr. Richards is terminated by us for any reason other than for cause, he will be entitled to severance compensation equal to two times his annual base compensation in effect at the time of termination payable in equal installments over a 24-month period following termination; provided, however, in the event his employment should be terminated by us other than for cause within six months following a change of control of the Company or a sale of substantially all of our drilling assets, or in anticipation of a change of control of the Company or a sale of substantially all our drilling assets, severance compensation will be payable in a lump sum on the date of termination.

Severance Agreement

Effective as of May 6, 2002, we entered into a severance agreement with Mr. Grundman pursuant to which we will make severance payments to Mr. Grundman totaling $840,000 in equal installments over a three-year period. In addition, the severance arrangement provides that Mr. Grundman will be entitled to receive a certain group medical and dental, life, executive life, accident and disability benefits for a three-year period following his termination, as well as an automobile allowance and certain additional payments to cover any short-fall in any payments made pursuant to our medical insurance coverage. Mr. Grundman's severance arrangement with us also provides that all unvested options to acquire shares of Common Stock that were granted to him became immediately vested and exercisable and that certain of those options will remain exercisable for a period of three years.

CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

In connection with the negotiation of the terms of a five-year employment agreement with Francis D. John, our Chairman of the Board, President and Chief Executive Officer, and as an inducement to Mr. John to enter into such employment agreement, we entered into a separate loan agreement with Mr. John dated as of August 2, 1999, which as amended through June 30, 2001, provided that $6.5 million in loans previously made by us to Mr. John, together with the accrued interest payable thereon (accruing at a rate equal to 125 basis points above LIBOR, adjusted monthly) would be forgiven ratably during the ten-year period commencing on July 1, 2001 and ending on June 30, 2011. The loan agreement provided that the foregoing forgiveness of indebtedness was conditioned upon Mr. John remaining employed by us during such period. In addition, in the event that Mr. John had been terminated by us for "Cause" (as defined in the agreement), or in the event that Mr. John had voluntarily terminated his employment with us, the loan agreement further provided that the entire remaining principal balance of these loans, together with accrued interest payable thereon, would become immediately due and payable by Mr. John. However, in the event that Mr. John's employment

had been terminated for "Good Reason," or as a result of Mr. John's death or "Disability," or as a result of a "Change in Control" (all as defined in that agreement), the loan agreement stipulated that the remaining principal balance outstanding on the loans, together with accrued interest thereon will be forgiven. This loan agreement further provided that with respect to any forgiveness of the payment of principal and interest on the loans, Mr. John would be entitled to receive a "gross-up" payment in an amount sufficient for him to pay any federal, state, or local income taxes that may be due and payable by him with respect to the forgiveness of such indebtedness (principal and interest). The loan agreement has been effectively superseded by Mr. John's new employment agreement that provided for a one-time retention incentive payment that was made and used to repay all amounts owed under the loan agreement (See "Management Employment Agreements with Executive Officers").

In connection with the negotiation of an employment agreement with Thomas K. Grundman, our former Executive Vice President of International Operations, Chief Financial Officer and Chief Accounting Officer, we made a $150,000 relocation loan to assist Mr. Grundman's relocation to our executive offices. Interest on this relocation loan accrued at a rate of 6.125% per annum. The relocation loan together with accrued interest was forgiven in three installments of $50,000 (plus accrued interest) on July 1, 2000, $50,000 (plus accrued interest) on July 1, 2001, and $50,000 (plus accrued interest) on May 6, 2002. Mr. Grundman also received "gross-up" payments in an amount sufficient for him to pay any federal, state, or local income taxes that became due and payable by him with respect to the forgiveness of such indebtedness (principal and interest).

In addition, in December 2001, we temporarily advanced Mr. John and Mr. Grundman $201,686 and $24,770, respectively, to satisfy certain Medicare tax obligations incurred by them. Mr. John has repaid his advance in full, and Mr. Grundman is obligated to repay his advance under the terms of his severance arrangement.

During the period since the beginning of our last fiscal year, Jim D. Flynt, our recently elected Senior Vice President Production Services, was indebted to us in the principal amount of $140,000 pursuant to a temporary relocation bridge loan that has since been repaid in full. Prior to its repayment, the loan accrued interest at a rate of 6% per annum.

OWNERSHIP OF CAPITAL STOCK

Management

The following table sets forth as of April 21, 2003, the number of shares of Common Stock beneficially owned by (i) each director and nominee, (ii) each executive officer, and (iii) all directors and executive officers of the Company as a group. Except as noted below, each holder has sole voting and investment power with respect to all shares of Common Stock listed as owned by such person.

Name of Beneficial Owner	Number of Shares(1)	Percentage of Outstanding Shares(2)
Francis D. John(3)	3,081,102	2.4%
David J. Breazzano(4)	290,000	*
Kevin P. Collins(5)	305,072	*
William D. Fertig(6)	85,000	*
W. Phillip Marcum(7)	305,072	*
Ralph S. Michael, III(8)	1,800	*
J. Robinson West(9)	32,500	*
Morton Wolkowitz(10)	820,302	*
Royce W. Mitchell(11)	100,000	*
James J. Byerlotzer(12)	382,456	*
Jim D. Flynt(13)	94,081	*
Steven A. Richards(14)	28,633	*
Directors and Executive Officers as a group (12 persons)	5,526,048	4.3%

* Less than 1%

(1) Includes all shares with respect to which each director or executive officer directly or indirectly, through any contract, arrangement, understanding, relationship or otherwise, has or shares the power to vote or to direct voting of such shares and/or to dispose or to direct the disposition of such shares. Includes shares that may be purchased under currently exercisable stock options and stock options exercisable within 60 days from April 21, 2003.

(2) Based on 128,551,471 shares of Common stock issued and outstanding at April 21, 2003, plus, for each beneficial owner, those number of shares underlying currently exercisable options and options exercisable within 60 days of April 21, 2003, held by each executive officer or director.

(3) Includes 3,010,000 shares issuable upon exercise of vested options and options exercisable within 60 days from April 21, 2003 and 602 shares held in the Company's 401(k) stock fund. Does not include 600,000 shares issuable pursuant to options that do not vest within 60 days of April 21, 2003.

(4) Includes 230,000 shares issuable upon the exercise of vested options and options exercisable within 60 days from April 21, 2003. Does not include 10,000 shares issuable pursuant to options that do not vest within 60 days of April 21, 2003.

(5) Includes 300,000 shares issuable upon the exercise of vested options and options exercisable within 60 days from April 21, 2003. Does not include 10,000 shares issuable pursuant to options that do not vest within 60 days of April 21, 2003.

(6) Includes 80,000 shares issuable upon the exercise of vested options and options exercisable within 60 days from April 21, 2003. Does not include 10,000 shares issuable pursuant to options that do not vest within 60 days of April 21, 2003.

(7) Includes 300,000 shares issuable upon the exercise of vested options and options exercisable within 60 days from April 21, 2003. Does not include 10,000 shares issuable pursuant to options that do not vest within 60 days of April 21, 2003.

(8) Includes 700 shares held jointly with his spouse.

(9)
Includes 32,500 shares issuable upon the exercise of vested options and options exercisable within 60 days from April 21, 2003. Does not include 7,500 shares issuable pursuant to options that do not vest within 60 days of April 21, 2003.

(10)
Includes 237,000 shares issuable upon the exercise of vested options and options exercisable within 60 days from April 21, 2003. Does not include 10,000 shares issuable pursuant to options that do not vest within 60 days of April 21, 2003.

(11)
Includes 100,000 shares issuable upon the exercise of vested options and options exercisable within 60 days from April 21, 2003. Does not include 100,000 shares issuable pursuant to options that do not vest within 60 days of April 21, 2003.

(12)
Includes 371,666 shares issuable upon the exercise of vested options and options exercisable within 60 days from April 21, 2003 and 384 shares held in the Company's 401(k) stock fund. Does not include 288,334 shares issuable pursuant to options that do not vest within 60 days of April 21, 2003.

(13)
Includes 93,333 shares issuable upon the exercise of vested options and options exercisable within 60 days from April 21, 2003 and 248 shares held in the Company's 401(k) stock fund. Includes 500 shares held by his spouse. Does not include 53,344 shares issuable pursuant to options that do not vest within 60 days of April 21, 2003.

(14)
Includes 28,333 shares issuable upon the exercise of vested options and options exercisable within 60 days from April 21, 2003 and 330 shares held in the Company's 401(k) fund. Does not include 56,667 shares issuable pursuant to options that do not vest within 60 days of April 21, 2003.

In addition, the following Named Executive Officer who was not an executive officer of the Company on April 21, 2003, beneficially owns Common Stock as follows (assuming that Mr. Grundman has not disposed of any Common Stock since he left the Company): Thomas K. Grundman 895,276 shares (includes 785,000 shares issuable upon the exercise of vested options and 276 shares held in the Company's 401(k) stock fund). These shares represented less than 1% of outstanding shares of Common Stock.

Certain Beneficial Owners

The following table sets forth, as of April 21, 2003, certain information regarding the beneficial ownership of Common Stock by each person, other than the Company's directors or executive officers, who is known by the Company to own beneficially more than 5% of the outstanding shares of Common Stock.

	Shares Beneficially Owned at April 21, 2003	
Name and Address of Beneficial Owner	**Number**	**Percentage of Outstanding(1)**
Perkins, Wolf, McDonnell & Co.(2) 810 S. Michigan Avenue, Suite 2600 Chicago, Illinois 60604	14,410,876(3)	11.2%
Berger, L.L.C.(4) 210 University Boulevard Suite 900 Denver, Colorado 80206	7,650,100(3)	6.0%

(1)
Based on 128,551,471 shares of Common stock outstanding at April 21, 2003.

(2)

As reported on Schedule 13G filed with the Commission on January 31, 2003.

(3) The Company believes that Perkins, Wolf, McDonnell & Co. shares voting power with respect to 7,650,100 of its shares with Berger, LLC and that, therefore, the 7,650,100 shares shown as being beneficially owned by Berger, LLC are the same securities shown as being beneficially owned by Perkins, Wolf, McDonnell & Co.

(4) As reported on Schedule 13G filed with the Commission on March 17, 2003.

PLAN OF DISTRIBUTION

We will issue common stock from time to time in connection with acquisitions by us or our subsidiaries of other businesses, assets or securities. We expect that the terms of the acquisitions involving the issuance of securities covered by this prospectus will be determined by direct negotiations with the owners or controlling persons of the businesses, assets or securities to be acquired by us or our subsidiaries. No underwriting discounts or commissions will be paid in connection with the issuance of our common stock, although finders' fees may be paid from time to time with respect to specific mergers or acquisitions. Any person receiving such fees may be deemed to be an underwriter within the meaning of the Securities Act.

LEGAL MATTERS

Certain legal matters in connection with this offering will be passed upon for us by Porter & Hedges, L.L.P.

EXPERTS

Our consolidated financial statements as of December 31, 2002, 2001 and 2000, and for each of the years in the three-year period ended December 31, 2002, have been included or incorporated by reference herein in reliance upon the report of KPMG LLP, independent certified public accountants, incorporated by reference herein, and upon the authority of such firm as experts in accounting and auditing.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

KEY ENERGY SERVICES, INC.

CONSOLIDATED BALANCE SHEETS

	December 31, 2002	June 30, 2002	June 30, 2001
	(Thousands, Except Share Data)		
ASSETS			
Current Assets:			
Cash and cash equivalents	$ 9,044	$ 54,147	$ 2,098
Accounts receivable, net of allowance for doubtful accounts ($4,439, $3,969 and $4,082, at December 31, 2002 and June 30, 2002 and 2001, respectively)	141,958	117,907	177,016
Inventories	10,243	7,776	16,547
Prepaid expenses and other current assets	14,329	12,243	10,489
Total current assets	175,574	192,073	206,150
Property and equipment:			
Well servicing equipment	935,911	776,271	723,724
Contract drilling equipment	128,199	124,191	119,122
Motor vehicles	79,110	68,977	64,907
Oil and gas properties and other related equipment, successful efforts method	48,362	44,439	44,245
Furniture and equipment	51,349	38,979	24,865
Buildings and land	48,922	40,247	37,812
Total property and equipment	1,291,853	1,093,104	1,014,675
Accumulated depreciation & depletion	(335,348)	(284,204)	(220,959)
Net property and equipment	956,505	808,900	793,716
Goodwill, net of accumulated amortization ($27,876, $27,856 and $28,168 at December 31, 2002 and June 30, 2002 and 2001, respectively)	322,270	201,069	189,875

	December 31, 2002	June 30, 2002	June 30, 2001
Deferred costs, net	13,503	12,580	17,624
Notes receivable related parties	251	274	6,050
Other assets	33,899	28,099	14,869
Total assets	1,502,002	1,242,995	1,228,284
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Accounts payable	28,818	24,625	42,544
Other accrued liabilities	57,823	49,465	48,923
Accrued interest	15,226	14,864	16,140
Current portion of long-term debt	7,008	7,674	7,946
Total current liabilities	108,875	96,628	115,553
Long-term debt, less current portion	472,336	420,717	470,578
Capital lease obligations, less current portion	14,221	15,219	15,383
Deferred revenue	8,460	10,001	14,104
Non-current accrued expenses	40,477	13,574	8,388
Deferred tax liability	161,265	149,990	127,400
Commitments and contingencies			
Stockholders' equity:			
Common stock, $0.10 par value; 200,000,000 shares authorized, 128,757,693, 110,308,463 and 101,440,166 shares issued, at December 31, 2002 and June 30, 2002 and 2001, respectively	12,876	11,031	10,144
Additional paid-in capital	673,249	514,752	444,768
Treasury stock, at cost; 416,666 shares at December 31, 2002 and June 30, 2002 and 2001	(9,682)	(9,682)	(9,682)
Accumulated other comprehensive income (loss)	(45,431)	(48,967)	62
Retained earnings	65,356	69,732	31,586
Total stockholders' equity	696,368	536,866	476,878
Total liabilities and stockholders' equity	$ 1,502,002	$ 1,242,995	$ 1,228,284

See the accompanying notes which are an integral part of these consolidated financial statements.

KEY ENERGY SERVICES, INC.

CONSOLIDATED STATEMENTS OF OPERATIONS

	Six Months Ended December 31, 2002	Year Ended June 30,		
		2002	2001	2000
		(Thousands, Except Per Share Data)		

	Year Ended June 30,			
REVENUES:				
Well servicing	$ 370,871	$ 706,629	$ 758,273	$ 559,492
Contract drilling	33,632	87,077	107,639	68,428
Other	4,495	8,858	7,350	9,812
Total revenues	408,998	802,564	873,262	637,732
COSTS AND EXPENSES:				
Well servicing	263,595	489,681	500,324	408,723
Contract drilling	23,416	60,561	77,366	58,299
Depreciation, depletion and amortization	51,111	78,265	75,147	70,972
General and administrative	48,239	59,494	60,118	51,637
Interest	22,743	43,332	56,560	71,930
Other expenses	1,934	4,531	4,464	4,147
Foreign currency transaction loss, Argentina		1,443		
(Gain) loss on retirement of debt	(18)	4,812	(684)	(2,191)
Total costs and expenses	411,020	742,119	773,295	663,517
Income (loss) before income taxes	(2,022)	60,445	99,967	(25,785)
Income tax benefit (expense)	519	(22,299)	(37,257)	6,826
Income (loss) before cumulative effect	(1,503)	38,146	62,710	(18,959)
Cumulative effect on prior years of change in accounting principle, net of tax (See Note 1)	(2,873)			
NET INCOME (LOSS)	(4,376)	38,146	62,710	(18,959)
EARNINGS (LOSS) PER SHARE:				
Basic before cumulative effect	$ (0.01)	$ 0.36	$ 0.64	$ (0.23)
Cumulative effect, net of tax	(0.02)			
Basic after cumulative effect	$ (0.03)	$ 0.36	$ 0.64	$ (0.23)
Diluted before cumulative effect	$ (0.01)	$ 0.35	$ 0.61	$ (0.23)
Cumulative effect, net of tax	(0.02)			
Diluted after cumulative effect	$ (0.03)	$ 0.35	$ 0.61	$ (0.23)
WEIGHTED AVERAGE SHARES OUTSTANDING:				
Basic	125,367	105,766	98,195	83,815
Diluted	125,367	107,462	102,271	83,815

See the accompanying notes which are an integral part of these consolidated financial statements.

KEY ENERGY SERVICES, INC.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Six Months Ended December 31, 2002	Year Ended June 30, 2002	2001	2000
			(Thousands)	
NET INCOME (LOSS)	$ (4,376)	$ 38,146	$ 62,710	$ (18,959)
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX:				
Derivative transition adjustment			(778)	
Oil and natural gas derivatives adjustment	(775)	(279)	306	
Amortization of oil and natural gas derivatives	609	(367)	558	
Currency translation gain (loss)	3,702	(48,383)	(32)	(1)
COMPREHENSIVE INCOME (LOSS), NET OF TAX	$ (840)	$ (10,883)	$ 62,764	$ (18,960)

See the accompanying notes which are an integral part of these consolidated financial statements.

KEY ENERGY SERVICES, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended December 31, 2002	Year Ended June 30, 2002	2001	2000
			(Thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:				
Net income (loss)	$ (4,376)	$ 38,146	$ 62,710	$ (18,959)
ADJUSTMENTS TO RECONCILE INCOME (LOSS) TO NET CASH PROVIDED BY (USED IN) OPERATING ACTIVITIES:				
Depreciation, depletion and amortization	51,111	78,265	75,147	70,972
Amortization of deferred debt issuance costs, discount and premium	2,154	3,005	4,947	5,919
Deferred income taxes	(552)	21,385	34,953	(1,238)
(Gain) loss on sale of assets	477	(668)	173	25
Foreign currency transaction loss, Argentina		1,443		
(Gain) loss on retirement of debt	(18)	4,812	(684)	(2,191)
Cumulative effect of a change in accounting principle, net of tax	2,873			
CHANGE IN ASSETS AND LIABILITIES NET OF EFFECTS FROM THE ACQUISITIONS:				
(Increase) decrease in accounts receivable	(4,951)	48,907	(53,813)	(31,205)

	Six Months Ended December 31, 2002	Year Ended June 30,		
(Increase) decrease in other current assets	7,655	(4,410)	(4,485)	(5,483)
Increase (decrease) in accounts payable, accrued interest and accrued expenses	(3,562)	(12,180)	29,414	18,875
Other assets and liabilities	6,783	11	(5,015)	(1,855)
Net cash provided by operating activities	57,594	178,716	143,347	34,860
CASH FLOWS FROM INVESTING ACTIVITIES:				
Capital expenditures well servicing	(27,422)	(57,857)	(51,064)	(26,469)
Capital expenditures contract drilling	(3,894)	(19,861)	(15,884)	(8,282)
Capital expenditures other	(10,180)	(15,979)	(15,802)	(3,422)
Proceeds from sale of fixed assets	788	4,258	3,415	2,722
Notes receivable from related parties			(1,500)	(2,315)
Acquisitions well servicing	(105,365)	(17,273)	(2,345)	
Acquisitions contract drilling		(2,037)	(800)	
Net cash used in investing activities	(146,073)	(108,749)	(83,980)	(37,766)
CASH FLOWS FROM FINANCING ACTIVITIES:				
Repayment of long-term debt	(16,413)	(309,559)	(373,998)	(39,438)
Repayment of capital lease obligations	(4,902)	(10,182)	(8,542)	(11,639)
Borrowings under line-of-credit	68,000			
Proceeds from equity offerings, net of expenses		42,590		100,571
Proceeds from long-term debt		258,500	205,210	12,000
Debt issuance costs	(3,026)	(1,585)	(4,958)	
Proceeds from forward sale, net of expenses				18,236
Proceeds from exercise of warrants			847	8,473
Proceeds from exercise of stock options	433	3,219	14,617	1,098
Other	(38)	(298)	(318)	
Net cash provided by (used in) financing activities	44,054	(17,315)	(167,142)	89,301
Effect of exchange rates on cash	(678)	(603)		
Net increase (decrease) in cash	(45,103)	52,049	(107,775)	86,395
Cash and cash equivalents at beginning of period	54,147	2,098	109,873	23,478
Cash and cash equivalents at end of period	$ 9,044	$ 54,147	$ 2,098	$ 109,873

See the accompanying notes which are an integral part of these consolidated financial statements.

KEY ENERGY SERVICES, INC.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

(THOUSANDS)

	Common Stock						
	Number of Shares	**Amount at Par**	**Additional Paid-In Capital**	**Treasury Stock**	**Accumulated Other Comprehensive Income**	**Retained Earnings**	**Total**
BALANCE AT JUNE 30, 1999	83,155	$ 8,317	$ 301,615	$ (9,682)	$ 9	$ (12,165)	$ 288,094
Foreign currency transition adjustment, net of tax					(1)		(1)
Exercise of warrants	2,431	243	8,230				8,473
Exercise of options	241	24	1,074				1,098
Conversion of 7% Debentures	380	38	3,568				3,606
Issuance of common stock in equity offering, net of offering costs	11,000	1,100	99,471				100,571
Other	3	1	4				5
Net loss						(18,959)	(18,959)
BALANCE AT JUNE 30, 2000	97,210	$ 9,723	$ 413,962	$ (9,682)	$ 8	$ (31,124)	$ 382,887
Derivative transition adjustment (see Note 6)					(778)		(778)
Oil and natural gas derivatives adjustment, net of tax (See Note 6)					306		306
Amortization of oil and natural gas derivatives (see Note 6)					558		558
Foreign currency transition adjustment, net of tax					(32)		(32)
Exercise of warrants	185	19	828				847
Exercise of options	3,106	308	14,309				14,617
Conversion of 7% Debentures	101	10	947				957
Issuance of common stock for acquisitions	838	84	8,036				8,120
Deferred tax benefit compensation expense			7,004				7,004
Other			(318)				(318)
Net income						62,710	62,710
BALANCE AT JUNE 30, 2001	101,440	$ 10,144	$ 444,768	$ (9,682)	$ 62	$ 31,586	$ 476,878
Oil and natural gas derivatives adjustment, net of tax (See Note 6)					(279)		(279)
Amortization of oil and natural gas derivatives (see Note 6)					(367)		(367)
Foreign currency translation adjustment, net of tax					(48,383)		(48,383)
Exercise of warrants	7	1	(1)				
Exercise of options	659	66	3,153				3,219
Issuance of common stock for acquisitions	2,801	280	24,787				25,067
Issuance of common stock in equity offering, net of offering costs	5,400	540	42,050				42,590
Other	1		(5)				(5)
Net income						38,146	38,146
BALANCE AT JUNE 30, 2002	110,308	$ 11,031	$ 514,752	$ (9,682)	$ (48,967)	$ 69,732	$ 536,866
Oil and natural gas derivatives adjustment, net of tax (See Note 6)					(775)		(775)

	Common Stock						
Amortization of oil and natural gas derivatives (see Note 6)					609		609
Foreign currency translation adjustment, net of tax					3,702		3,702
Exercise of options	139	14	419				433
Issuance of common stock for acquisitions	18,311	1,831	158,115				159,946
Other			(37)				(37)
Net loss						(4,376)	(4,376)
BALANCE AT DECEMBER 31, 2002	128,758	$ 12,876	$ 673,249	$ (9,682)	$ (45,431)	$ 65,356	$ 696,368

See the accompanying notes which are an integral part of these consolidated financial statements.

KEY ENERGY SERVICES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2002, June 30, 2002, 2001 and 2000

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The Company

Based on the number of rigs owned and available industry data, Key Energy Services, Inc. (the "Company" or "Key"), is the largest onshore, rig-based well servicing contractor in the world, with approximately 1,489 well service rigs and 2,295 oilfield service vehicles as of December 31, 2002. The Company provides a complete range of well services to major oil companies and independent oil and natural gas production companies, including: rig-based well maintenance, workover, completion, and recompletion services (including horizontal recompletions); oilfield trucking services; well intervention services; and ancillary oilfield services. Key conducts well servicing operations onshore in the continental United States in the following regions: Gulf Coast (including South Texas, Central Gulf Coast of Texas, and South Louisiana), Permian Basin of West Texas and Eastern New Mexico, Mid-Continent (including the Anadarko, Hugoton and Arkoma Basins, Forth Worth Basin and the ArkLaTex region), Four Corners (including the San Juan, Piceance, Uinta, and Paradox Basins), Eastern (including the Appalachian, Michigan and Illinois Basins), Rocky Mountains (including the Denver-Julesberg, Powder River, Wind River, Green River and Williston Basins), and California (the San Joaquin Basin), and internationally in Argentina and Canada (Ontario) and Egypt. Based on the number of rigs owned and available industry data, the Company is also a leading onshore drilling contractor, with approximately 79 land drilling rigs as of December 31, 2002. Key conducts land drilling operations in a number of major domestic producing basins, as well as in Argentina and in Canada (Ontario). Key also produces and develops oil and natural gas reserves in the Permian Basin region and Texas Panhandle.

Basis of Presentation

The Company's consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries. All significant inter-company transactions and balances have been eliminated. The accounting policies presented below have been followed in preparing the accompanying consolidated financial statements.

Estimates and Uncertainties

Preparation of the accompanying consolidated financial statements in conformity with generally accepted accounting principles in the United States of America requires management to make estimates and assumptions that affect the reported amount of assets and liabilities and disclosures of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Revenue Recognition

Well Servicing Rigs. Well servicing rig services consists primarily of maintenance services, workover services, completion services and plugging and abandonment services. The Company recognizes revenue when services are performed, collection of the relevant receivables is probable, persuasive evidence of an arrangement exists and the price is fixable or determinable. Primarily, the Company prices well servicing rig services by the hour of service performed. Depending on the type of job, the Company may charge by the project or by the day.

Oilfield Trucking. Oilfield trucking consists primarily of fluid and equipment transportation services and frac tanks which are used in conjunction with fluid hauling services. The Company recognizes revenue when services are performed, collection of the relevant receivables is probable, persuasive evidence of an arrangement exists and the price is fixable or determinable. Primarily, the Company prices oilfield trucking services by the project or by the quantities hauled.

Well Intervention Services. Well intervention services consists primarily of fishing and rental tool services and pressure pumping services. The Company recognizes revenue when services are performed, collection of the relevant receivables is probable, persuasive evidence of an arrangement exists and the price is fixable or determinable. Generally, the Company prices fishing and rental tool services by the day and pressure pumping services by the job.

Ancillary Oilfield Services. Ancillary oilfield services includes wireline services, wellsite construction, roustabout services, foam units and air drilling services among others. The Company recognizes revenue when services are performed, collection of the relevant receivables is probable, persuasive evidence of an arrangement exists and the price is fixable or determinable. The Company prices ancillary oilfield services by the hour, day or project depending on the type of service performed.

Contract Drilling. The Company recognizes revenue when services are performed, collection of the relevant receivables is probable, persuasive evidence of an arrangement exists and the price is fixable or determinable. Contract drilling services are primarily provided under standard day rate, and, to a lesser extent, footage or turnkey contracts. The Company recognizes revenues on day rate contracts as earned daily. The Company follows the percentage of completion method of accounting for footage contracts. Under this method, revenues are recognized over the time it takes to drill the well based on the footage completed. On turnkey contracts, the Company recognizes revenue when the well is completed.

Inventories

Inventories, which consist primarily of oilfield service parts and supplies held for consumption, are valued at the lower of average cost or market.

Property and Equipment

The Company provides for depreciation and amortization of oilfield service and related equipment using the straight-line method, excluding its drilling rigs, over the following estimated useful lives of the assets:

Description	Years
Well service rigs	25
Motor vehicles	5
Furniture and equipment	3-7
Buildings and improvements	10-40
Gas processing facilities	10
Disposal wells	15-30
Trucks, trailers and related equipment	7-15

The components of a well service rig that generally require replacement during the rig's life are depreciated over their estimated useful lives, which range from three to 15 years. The basic rigs, excluding components, have estimated useful lives from date of original manufacture ranging from 25 to 35 years. Salvage values are assigned to the rigs based on an estimate of 10%.

The Company uses the units-of-production method to depreciate its drilling rigs. This method takes into consideration the number of days the rigs are actually in service each month and depreciation is recorded for at least 15 days each month for each rig that is available for service. The Company believes that this method appropriately reflects its financial results by matching revenues with expenses and appropriately reflects how the assets are to be used over time.

The Company uses the successful efforts method of accounting for its oil and gas properties. Under this method, all costs associated with productive wells and nonproductive development wells are capitalized, while nonproductive exploration costs and geological and geophysical costs (if any), are expensed. Capitalized costs relating to proved properties are depleted using the units-of-production method. Due to the immateriality of the oil and natural gas operations in terms of revenue, net income and total assets, the Company does not provide disclosures on its oil and gas properties in accordance with FASB Statement No. 69, Disclosures about Oil and Gas Producing Activities ("SFAS 69").

On July 1, 2002, the Company adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations ("SFAS 143"). Adoption of SFAS 143 is required for all companies with fiscal years beginning after June 15, 2002. The new standard requires the Company to recognize a liability for the present value of all legal obligations associated with the retirement of tangible long-lived assets and capitalize an equal amount as a cost of the asset depreciating the additional cost over the estimated useful life of the asset. On July 1, 2002, the Company recorded additional costs, net of accumulated depreciation, of approximately $3,347,000, a non-current liability of approximately $7,980,000 and an after-tax charge of approximately $2,873,000 for the cumulative effect on prior years for depreciation of the additional costs and accretion expense on the liability related to expected abandonment costs of its oil and natural gas producing properties and salt water disposal wells. At December 31, 2002, the asset retirement obligation was approximately $9,231,000, and the increase in the balance from July 1, 2002 of $1,251,000 is due to accretion expense of approximately $226,000 and asset retirement obligations of QSI of $1,025,000 assumed in the purchase transaction. The pro forma amounts of the asset retirement obligation as of June 30, 2002, 2001, 2000 and 1999, were approximately $7,980,000, $7,581,000, $7,182,000 and $6,783,000, respectively. The pro forma amounts of the asset retirement obligation were measured using information, assumptions and interest rates as of the adoption date of July 1, 2002. Pro forma net income (loss) and related per share amounts for the years ended June 30, 2002, 2001 and 2000, assuming SFAS 143 had been applied in each year are as follows:

	Year Ended		
	2002	**2001**	**2000**
	(Thousands, except per share amount)		
Pro forma net income (loss)	$ 37,894	$ 62,460	$ (19,252)
Earnings (loss) per share			
Basic	$ 0.36	$ 0.64	$ (0.23)
Diluted	$ 0.35	$ 0.61	$ (0.23)

On July 1, 2002, the Company adopted Statement of Financial Accounting Standards No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets ("SFAS 144"). This statement requires that long-lived assets including certain identifiable intangibles, held and used by the Company, be reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. For purposes of applying this statement, the Company groups its long-lived assets on a yard-by-yard basis and compares the estimated future cash flows of each yard to the yard's net carrying value. The yard level represents the lowest level for which identifiable cash flows are available. The Company would record an impairment charge, reducing the yard's net carrying value to an estimated fair value, if the estimated future cash flows were less than the yard's net carrying value. No impairment charges have been required. Prior to July 1, 2002, the Company applied the provisions of FASB Statement No. 121, Accounting for Impairment or Disposal of Long Lived Assets.

Hedging and Derivative Financial Instruments

The Company uses derivative financial instruments, primarily commodity option contracts to reduce the exposure of its oil and gas producing operations to changes in the market price of natural gas and crude oil and to fix the price for natural gas and crude oil independently of the physical sale.

The financial instruments that the Company accounts for as hedging contracts must meet the following criteria: the underlying asset or liability must expose the Company to price risk that is not offset in another asset or liability, the hedging contract must reduce that price risk, and the instrument must be designated as a hedge at the inception of the contract and throughout the contract period. In order to qualify as a hedge, there must be clear correlation between changes in the fair value of the financial instrument and the fair value of the underlying asset or liability such that changes in the market value of the financial instrument will be offset by the effect of price rate changes on the exposed items.

Prior to the adoption of SFAS 133, premiums paid for commodity option contracts, which qualify as hedges, are amortized to oil and natural gas sales over the terms of the contracts. Unamortized premiums are included in other assets in the consolidated balance sheet. Amounts receivable under the commodity option contracts are accrued as an increase in oil and natural gas sales for the applicable periods.

Effective July 1, 2000, the Company adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS 133") as amended by SFAS No. 137 and No. 138 ("SFAS 138"). SFAS 133 establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts and hedging activities. It requires the recognition of all derivative instruments as assets and liabilities in the Company's balance sheet and measurement of those instruments at fair value. The accounting treatment of changes in fair value is dependent upon whether or not a derivative instrument is designated as a hedge and if so, the type of hedge. For derivatives designated as cash flow hedges, changes in fair value are recognized in other comprehensive income until the hedged item is recognized in earnings. See Note 6.

Comprehensive Income

The Company follows the provisions of Statement of Financial Accounting Standards No. 130, "Reporting Comprehensive Income" ("SFAS 130"). SFAS 130 establishes standards for reporting and presentation of comprehensive income and its components. SFAS 130 requires that all items that are required to be recognized under accounting standards as components of comprehensive income be reported in a financial statement that is displayed with the same prominence as other financial statements. In accordance with the provisions of SFAS 130, the Company has presented the components of comprehensive income in its Consolidated Statements of Comprehensive Income.

Environmental

The Company is subject to extensive federal, state and local environmental laws and regulations. These laws, which are constantly changing, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the adverse environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures of a non-capital nature are recorded when environmental assessment and/or remediation is probable, and the costs can be reasonably estimated.

Goodwill and Other Intangible Assets

The Company adopted Statement of Financial Accounting Standards No. 142, Goodwill and Other Intangible Assets ("SFAS 142") on July 1, 2001. SFAS 142 eliminates the amortization for goodwill and other intangible assets with indefinite lives. Intangible assets with lives restricted by contractual, legal, or other means will continue to be amortized over their useful lives. Goodwill and other intangible assets not subject to amortization are tested for impairment annually or more frequently if events or changes in circumstances indicate that the asset might be impaired. SFAS 142 requires a two-step process for testing impairment. First, the fair value of each reporting unit is compared to its carrying value to determine whether an indication of impairment exists. If impairment is indicated, then the fair value of the reporting unit's goodwill is determined by allocating the unit's fair value to its assets and liabilities (including any unrecognized intangible assets) as if the reporting unit had been acquired in a business combination. The amount of impairment for goodwill is measured as the excess of its carrying value over its fair value. The Company completed its assessment of goodwill impairment as of the date of adoption during the three months ended December 31, 2001, as allowed by SFAS 142, and a subsequent annual impairment assessment as of June 30, 2002. The assessments did not result in an indication of goodwill impairment as of either date.

Intangible assets subject to amortization under SFAS 142 consist of noncompete agreements and patents. Amortization expense for the noncompete agreements is calculated using the straight-line method over the period of the agreement, ranging from three to seven years. Amortization expense for patents is calculated using the straight-line method over the useful life of the patent, ranging from five to seven years.

The gross carrying amount of noncompete agreements subject to amortization totaled approximately $18,669,000, $11,727,000 and $8,324,000 at December 31, 2002 and June 30, 2002 and 2001, respectively. Accumulated amortization related to these intangible assets totaled approximately $7,511,000, $6,130,000 and $4,953,000 at December 31, 2002 and June 30, 2002 and 2001, respectively. Amortization expense for the six months ended December 31, 2002 was approximately $2,333,000 and for the years ended June 30, 2002, 2001 and 2000 was approximately $1,914,000, $1,801,000 and $1,410,000, respectively. Amortization expense for the next five succeeding years is estimated to be approximately $3,885,000, $2,750,000, $2,122,000, $1,711,000 and $662,000.

The gross carrying amount of patents subject to amortization totaled approximately $2,380,000 at December 31, 2002. The Company acquired patents on July 16, 2002. Accumulated amortization and amortization expense related to these intangible assets totaled approximately $160,000 as of and for the six months ended December 31, 2002. Amortization expense for the next five succeeding years is estimated to be approximately $511,000, $352,000, $352,000, $352,000, and $296,000.

The Company has identified its reporting segments to be well servicing and contract drilling. Goodwill allocated to such reporting segments at December 31, 2002 is approximately $307,987,000 and $14,283,000, and at June 30, 2002 is $186,819,000 and $14,250,000, respectively. The change in the carrying amount of goodwill for the six months ended December 31, 2002 of $121,201,000 and for the year ended June 30, 2002 of approximately $11,194,000 relates principally to goodwill from well servicing assets acquired during the period and the translation adjustment for Argentina.

The effects of the adoption of SFAS 142 on net income and earnings per share for the years ended June 30, 2001 and 2000 are as follows:

	Year Ended June 30,	
	2001	**2000**
	(thousands, except per share data)	
Reported net income (loss)	$ 62,710	$ (18,959)
Add back: goodwill amortization	9,322	9,840
Adjusted net income (loss)	72,032	(9,119)
Basic Earnings (Loss) Per Share:		
Reported net income (loss)	$ 0.64	$ (0.23)
Add back: goodwill amortization	0.09	0.12
Adjusted net income (loss)	$ 0.73	$ (0.11)
Diluted Earnings (Loss) Per Share:		
Reported net income (loss)	$ 0.61	$ (0.23)
Add back: goodwill amortization	0.09	0.12
Adjusted net income (loss)	$ 0.70	$ (0.11)

Deferred Costs

Deferred costs totaling $35,955,000 at December 31, 2002 and $32,928,000 and $31,052,000 at June 30, 2002 and 2001, respectively, represent debt issuance costs and are recorded net of accumulated amortization of $22,452,000 at December 31, 2002 and $20,348,000 and $13,428,000 at June 30, 2002 and 2001, respectively. Deferred costs are amortized to interest expense using the straight-line method over the life of each applicable debt instrument or to gain (loss) on retirement of debt. This method approximates the amortization which would be recorded using the effective interest method. Amortization of deferred costs totaled approximately $2,103,000 for the six months ended December 31, 2002 and $2,581,000, $3,578,000 and $5,176,000 for the years ended June 30, 2002, 2001 and 2000, respectively. Unamortized debt issuance costs written off and included in the determination of the gain (loss) on retirement of debt for the years ended June 30, 2002 and 2001, totaled approximately $4,339,000 and $2,583,000, respectively. For the six months ended December 31, 2002 and the year ended June 30, 2000, there were no unamortized debt issuance costs included in the determination of gain (loss) on the retirement of debt.

Income Taxes

The Company accounts for income taxes based upon Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes" ("SFAS 109"). Under SFAS 109, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using statutory tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rate is recognized in income in the period that includes the statutory enactment date. A valuation allowance for deferred tax assets is recognized when it is more likely than not that the benefit of deferred tax assets will not be realized.

The Company and its eligible subsidiaries file a consolidated U. S. federal income tax return. Certain subsidiaries that are consolidated for financial reporting purposes are not eligible to be included in the consolidated U. S. federal income tax return and separate provisions for income taxes have been determined for these entities or groups of entities.

Earnings Per Share

The Company presents earnings per share information in accordance with the provisions of Statement of Financial Accounting Standards No. 128, "Earnings per Share" ("SFAS 128"). Under SFAS 128, basic earnings per common share are determined by dividing net earnings applicable to common stock by the weighted average number of common shares actually outstanding during the year. Diluted earnings per common share is based on the increased number of shares that would be outstanding assuming conversion of dilutive outstanding convertible securities using the "as if converted" method.

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	Six Months Ended December 31, 2002	Year Ended June 30,		
		2002	2001	2000
	(Thousands, except per share data)			
Basic EPS Computation:				
Numerator				
Net income (loss) before cumulative effect	$ (1,503)	$ 38,146	$ 62,710	$ (18,959)
Cumulative effect, net of tax(1)	(2,873)			
Net income (loss)	$ (4,376)	$ 38,146	$ 62,710	$ (18,959)
Denominator				
Weighted average common shares outstanding	125,367	105,766	98,195	83,815
Basic EPS:				
Before cumulative effect (loss)	$ (0.01)	$ 0.36	$ 0.63	$ (0.23)
Cumulative effect, net of tax(1)	(0.02)			
Net income (loss)	$ (0.03)	$ 0.36	$ 0.63	$ (0.23)
Diluted EPS Computation:				
Numerator				
Net income (loss) before cumulative effect and effect of dilutive securities, tax effected	$ (1,503)	$ 38,146	$ 62,710	$ (18,959)
Convertible securities			5	
Net income (loss) before cumulative effect	(1,503)	38,146	62,715	(18,959)
Cumulative effect, net of tax(1)	(2,873)			

	Six Months Ended December 31, 2002	Year Ended June 30,		
Net income (loss)	$ (4,376)	$ 38,146	$ 62,715	$ (18,959)
Denominator				
Weighted average common shares outstanding	125,367	105,766	98,195	83,815
Warrants		402	205	
Stock Options		1,294	3,853	
7% Convertible Debentures			18	
	125,367	107,462	102,271	83,815
Diluted EPS:				
Before cumulative effect	$ (0.01)	$ 0.35	$ 0.61	$ (0.23)
Cumulative effect, net of tax(1)	(0.02)			
Net income (loss)	$ (0.03)	$ 0.35	$ 0.61	$ (0.23)

(1) See section entitled Property and Equipment set forth in this Note 1.

The diluted earnings per share calculation for the years ended June 30, 2002 and 2001 excludes the effect of the potential exercise of stock options of 1,177,000 and 360,000, respectively, and the potential conversion of the Company's 5% Convertible Subordinated Notes because the effects of such instruments on earnings per share would be anti-dilutive.

The diluted earnings per share calculation for the six months ended December 31, 2002 and the year ended June 30, 2000 excludes the effect of the potential conversion of all of the Company's then outstanding convertible debt and the potential exercise of all of the Company's then outstanding warrants and stock options because the effects of such instruments on loss per share would be anti-dilutive.

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Concentration of Credit Risk

Financial instruments, which potentially subject the Company to concentrations of credit risk, consist primarily of temporary cash investments and trade receivables. The Company restricts investment of temporary cash investments to financial institutions with high credit standing and, by policy, limits the amount of credit exposure to any one financial institution. The Company's customer base consists primarily of multi-national and independent oil and natural gas producers. This may affect the Company's overall exposure to credit risk either positively or negatively in as much as its customers are affected by economic conditions in the oil and gas industry, which have historically been cyclical. However, account receivables are well diversified among many customers and a significant portion of the receivables are from major oil companies, which management believes minimizes potential credit risk. Historically, credit losses have been insignificant. Receivables are generally not collateralized, although the Company may generally secure a receivable at any time by filing a mechanic's or material-man's lien on the well serviced. The Company maintains reserves for potential credit losses, and such losses have been within management's expectations.

Key's customers include major oil companies, independent oil and natural gas production companies, and foreign national oil and natural gas production companies. One customer during the year ended June 30, 2002, Occidental Petroleum Corporation, accounted for approximately 10% of Key's consolidated revenues. The Company did not have any one customer which represented 10% or more of consolidated revenues for the six months ended December 31, 2002 or the years ended June 30, 2001 or 2000.

Stock-Based Compensation

The Company accounts for stock option grants to employees using the intrinsic value method of accounting prescribed by APB Opinion No. 25 ("APB 25"), "Accounting for Stock Issued to Employees." Under the Company's stock incentive plan, which is described more fully in Note 8, the price of the stock on the grant date is the same as the amount an employee must pay to exercise the option to acquire the stock;

accordingly, the options have no intrinsic value at grant date, and in accordance with the provisions of APB 25, no compensation cost is recognized.

Statement of Financial Accounting Standards No. 123 ("SFAS 123"), "Accounting for Stock-Based Compensation," sets forth alternative accounting and disclosure requirements for stock-based compensation arrangements. Companies may continue to follow the provisions of APB 25 to measure and recognize employee stock-based compensation; however, SFAS 123 requires disclosure of pro forma net income and earnings per share that would have been reported under the fair value based recognition provisions of SFAS 123. The following table illustrates the effect on net income and earnings per share if the Company had applied the fair value recognition provisions of SFAS 123 to stock-based employee compensation.

	Six Months Ended December 31, 2002	Year Ended June 30, 2002	Year Ended June 30, 2001	Year Ended June 30, 2000
	(Thousands, except per share data)			
Net income (loss):				
As reported	$ (4,376)	$ 38,146	$ 62,710	$ (18,959)
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of tax	(4,994)	(11,826)	(10,372)	(6,725)
Pro forma	$ (9,370)	$ 26,320	$ 52,338	$ (25,684)
Basic earnings per share:				
As reported	$ (0.03)	$ 0.36	$ 0.64	$ (0.23)
Pro forma	(0.07)	0.25	0.53	(0.31)
Diluted earnings per share:				
As reported	$ (0.03)	$ 0.35	$ 0.61	$ (0.23)
Pro forma	(0.07)	0.24	0.51	(0.31)

See Note 8 for additional information regarding the computations presented here.

Foreign Currency Gains and Losses

The local currency is the functional currency for the Company's foreign operations in Argentina and Canada. The cumulative translation gains and losses, resulting from translating each foreign subsidiary's financial statements from the functional currency to U.S. dollars, is included in other comprehensive income and accumulated in stockholders' equity until a partial or complete sale or liquidation of the Company's net investment in the foreign entity.

Cash and Cash Equivalents

The Company considers all unrestricted highly liquid investments with less than a three-month maturity when purchased, as cash equivalents.

Reclassifications

Certain reclassifications have been made to the consolidated financial statements for the years ended June 30, 2001 and 2000 to conform to the year ended June 30, 2002 and the six months ended December 31, 2002 presentation. The reclassifications consist primarily of reclassifying certain items from general and administrative expense to direct expenses. In addition on July 1, 2002, the Company adopted the provisions of SFAS 145. See Note 19.

Change in Fiscal Year

In December 2002, the Company's Board of Directors approved the Company's change of its fiscal year end from June 30 to December 31 of each year. The unaudited financial information for the six-month period ended December 31, 2001, is as follows:

	Six Months Ended December 31, 2001 (thousands, except per share data)
Revenues	$ 462,574
Operating profit	165,810
Income tax benefit	(29,419)
Net income	48,635
Earnings per share	
Basic	0.47
Diluted	0.47

2. BUSINESS AND PROPERTY ACQUISITIONS

During the six months ended December 31, 2002, the Company completed several small acquisitions for total consideration of $15,620,000, which consisted of a combination of cash, a deferred non-compete payment and shares of the Company's common stock. During the years ended June 30, 2002 and 2001, the Company completed several small acquisitions for total consideration of $44,378,000 and $11,965,000, respectively, which consisted of a combination of cash, notes and shares of the Company's common stock. Other than QSI, none of the acquisitions completed in the six months ended December 31, 2002 or the years ended June 30, 2002 and 2001 were material individually or in the aggregate, thus the pro forma effect of these acquisitions is not presented. Each of the acquisitions was accounted for using the purchase method and the results of the operations generated from the acquired assets are included in the Company's results of operations as of the completion date of each acquisition. There were no acquisitions completed by the Company for the year ended June 30, 2000.

Acquisition of Q Services, Inc.

On July 19, 2002, Key acquired Q Services, Inc. ("QSI") pursuant to an Agreement and Plan of Merger dated May 13, 2002, as amended, by and among Key, Key Merger Sub, Inc. and QSI. As consideration for the acquisition, the Company issued approximately 17.1 million shares of its common stock to the QSI shareholders and paid approximately $94.2 million in cash at the closing to retire debt and preferred stock of QSI and to satisfy certain other obligations of QSI. In addition to assuming the positive working capital of QSI, the Company incurred other direct acquisition costs and assumed certain other liabilities of QSI, resulting in the Company recording an aggregate purchase price of approximately $250 million. The value of the shares issued was based on the closing price of the Key common stock on the closing date of $8.75 per share. The results of QSI's operations have been included in the consolidated financial statements since the closing date. Prior to the acquisition, QSI was a privately held corporation conducting field production, pressure pumping, and other service operations in Louisiana, New Mexico, Oklahoma, Texas, and the Gulf of Mexico. The Company and QSI operated in adjacent and /or overlapping locations and expect to realize future cost savings and synergies in connection with the merger.

The following table summarizes the estimated fair value of the assets acquired and liabilities assumed at the date of acquisition:

	At July 19, 2002 (Thousands)
Current assets	$ 37,734
Property and equipment	139,023
Intangible assets	3,242

	At July 19, 2002
Other assets	344
Goodwill	119,174
Total assets acquired	299,517
Current liabilities	17,393
Capital lease obligations	77
Non-current accrued expenses	17,908
Deferred tax liability	14,347
Total liabilities assumed	49,725
Net assets acquired	249,792

The $3,242,000 of intangible assets consists of noncompete agreements which have a weighted-average useful life of approximately two years. The $119,174,000 of goodwill was allocated to the well servicing reporting segment. Of that amount, approximately $11,645,000 is expected to be deductible for income taxes.

The following unaudited pro forma results of operations have been prepared as though QSI had been acquired on July 1, 2001. Pro forma amounts are not necessarily indicative of the results that may be reported in the future.

	Six Months Ended	
	12/31/02	12/31/01
	(Thousands, except per share amount)	
Revenues	$ 416,701	$ 566,198
Income (loss) before cumulative effect of a change in accounting principle, net of tax	(2,563)	60,568
Cumulative effect of a change in accounting principle, net of tax	(2,873)	
Net income (loss)	(5,436)	60,568
Basic earnings (loss) per share	$ (0.04)	0.51

3. COMMITMENTS AND CONTINGENCIES

Various suits and claims arising in the ordinary course of business are pending against the Company. Management does not believe that the disposition of any of these items will result in a material adverse impact to the consolidated financial position, results of operations or cash flows of the Company.

In order to retain qualified senior management, the Company enters into employment agreements with its executive officers. These employment agreements run for periods ranging from three to five years, but can be automatically extended on a yearly basis unless terminated by the Company or the executive officer. In addition to providing a base salary for each executive officer, the employment agreements provide for severance payments for each executive officer equal to three years of the executive officer's base salary. On December 1, 2001, the Company paid to Mr. John an incentive retention payment in connection with his amended and restated employment agreement, which Mr. John will earn over a ten-year period beginning on June 30, 2002 (See Note 12). At December 31, 2002 the annual base salaries for the executive officers covered under such employment agreements totaled approximately $1,190,000. The Company also enters into employment agreements with other key employees as it deems necessary in order to retain qualified personnel.

4. LONG-TERM DEBT

The components of the Company's long-term debt are as follows:

	December 31, 2002	June 30, 2002	June 30, 2001
		(Thousands)	
Senior Credit Facility Revolving Loans(i)	$ 52,000		$ 2,000
8 3/8% Senior Notes Due 2008(ii)	276,331	276,433	175,000
14% Senior Subordinated Notes Due 2009(iii)	94,411	94,257	134,466
5% Convertible Subordinated Notes Due 2004(iv)	49,554	49,951	158,426
Capital lease obligations	21,164	22,829	22,964
Other notes payable	105	140	1,051
	493,565	443,610	493,907
Less current portion	7,008	7,674	7,946
Total long-term debt	$ 486,557	$ 435,936	$ 485,961

(i) Senior Credit Facility

On July 15, 2002, the Company entered into a Third Amended and Restated Credit Agreement, as amended by the First Amendment to the Third Amended and Restated Credit Agreement (the "Senior Credit Facility"). The Senior Credit Facility consists of a $150,000,000 revolving loan facility with a $75,000,000 sublimit for letters of credit. The loans are secured by most of the tangible and intangible assets of the Company. The revolving loan commitment will terminate on July 15, 2005 and all revolving loans must be paid on or before that date. The revolving loans bear interest based upon, at the Company's option, the prime rate plus a variable margin of 0.00% to 1.00% or a Eurodollar rate plus a variable margin of 1.75% to 3.00%.

The Senior Credit Facility contains various financial covenants, including: (i) a maximum consolidated senior leverage ratio of 3.25 to 1.00, (ii) a minimum consolidated fixed coverage ratio of 1.10 to 1.00, and (iii) a maximum consolidated total leverage ratio of 4.25 to 1.00. The Company is also required to maintain a minimum net worth of $436,972,000 plus (i) 50% of consolidated net income and (ii) 75% of the net cash proceeds from the sale of equity. As of December 31, 2002, the Company was in compliance with all covenants contained in the Senior Credit Facility.

The Senior Credit Facility subjects the Company to other restrictions, including restrictions upon the Company's ability to incur additional debt, liens and guarantee obligations, to merge or consolidate with other persons, to make acquisitions, to sell assets, to make dividends, purchases of our stock or subordinated debt, or to make investments, loans and advances or changes to debt instruments and

organizational documents. All obligations under the New Senior Credit Facility are guaranteed by most of the Company's subsidiaries and are secured by most of the Company's assets, including the Company's accounts receivable, inventory and most equipment.

The Company drew down approximately $43 million on its revolver under the Company's prior senior credit facility (the "Prior Senior Credit Facility") on January 14, 2002 in order to redeem a portion of the 14% Senior Subordinated Notes then outstanding. The funds were repaid with the issuance of additional 8 3/8% Notes in March 2002.

During the year ended June 30, 2001, a portion of the net proceeds from the 2000 Equity Offering (see Note 8) was used to repay the entire outstanding balance of the Tranche A term loan then outstanding under the Prior Senior Credit Facility and $2.3 million of the Tranche B term loan then outstanding under the Prior Senior Credit Facility. In addition, $65 million of the net proceeds from the 2000 Equity Offering were used to reduce the principal amount outstanding under the revolver. The remainder of the net proceeds of the 2000 Equity Offering was used to retire other long-term debt. A portion of the proceeds from the Company's 8 3/8% Senior Note offering in calendar year 2001 was used to repay the entire outstanding balance of the Tranche B term loan then outstanding under the Prior Senior Credit Facility and approximately $59.1 million under the revolver.

At December 31, 2002, there was an outstanding balance of $52,000,000 under the revolving loans. As of June 30, 2002, there was no outstanding balance under the revolving loans under the Prior Senior Credit Facility. Additionally, the Company had outstanding letters of credit of approximately $34,963,000 as of December 31, 2002 and $27,963,000 and $11,995,000 as of June 30, 2002 and 2001, respectively, under the Prior Senior Credit Facility related to its workers' compensation insurance.

(ii) 8$^3/_8$% Senior Subordinated Notes

On March 6, 2001, the Company completed a private placement of $175,000,000 of 8$^3/_8$% Senior Notes due 2008 (the "8$^3/_8$% Senior Notes"). The net cash proceeds from the private placement were used to repay all of the remaining balance of the original term loans under the Prior Senior Credit Facility, and a portion of the revolving loan facility under the Senior Credit Facility then outstanding. On March 1, 2002, the Company completed a public offering of an additional $100,000,000 of 8$^3/_8$% Senior Notes due 2008. The net cash proceeds from the public offering were used to repay all of the remaining balance of the revolving loan facility under the Prior Senior Credit Facility. The 8$^3/_8$% Senior Notes are senior unsecured obligations. The 8$^3/_8$% Senior Notes are effectively subordinated to Key's secured indebtedness which includes borrowings under the Senior Credit Facility.

On and after March 1, 2005, the Company may redeem some or all of the 8$^3/_8$% Senior Notes at any time at varying redemption prices in excess of par, plus accrued interest. In addition, before March 1, 2004, the Company may redeem up to 35% of the aggregate principal amount of the 8$^3/_8$% Senior Notes with the proceeds of certain sales of equity at 108.375% of par plus accrued interest.

At December 31, 2002, $275,000,000 principal amount of the 8$^3/_8$% Senior Notes remained outstanding. The 8$^3/_8$% Senior Notes require semi-annual interest payments on March 1 and September 1 of each year. Interest of approximately $11,516,000 was paid on September 1, 2002. As of December 31, 2002, the Company was in compliance with all covenants contained in the 8$^3/_8$% Senior Notes.

(iii) 14% Senior Subordinated Notes

On January 22, 1999, the Company completed the private placement of 150,000 units (the "Units") consisting of $150,000,000 of 14% Senior Subordinated Notes due 2009 (the "14% Senior Subordinated Notes") and 150,000 warrants to purchase 2,173,433 shares of the Company's Common Stock at an exercise price of $4.88125 per share (the "Unit Warrants"). The net cash proceeds from the private

placement were used to repay substantially all of the remaining $148,600,000 principal amount (plus accrued interest) owed under the Company's bridge loan facility arranged in connection with the acquisition of Dawson Production Services, Inc. ("Dawson").

On and after January 15, 2004, the Company may redeem some or all of the 14% Senior Subordinated Notes at any time at varying redemption prices in excess of par, plus accrued interest. In addition, before January 15, 2002, the Company was allowed to redeem up to 35% of the aggregate principal amount of the 14% Senior Subordinated Notes at 114% of par plus accrued interest with the proceeds of certain sales of equity. During the year ended June 30, 2001, the Company exercised its right of redemption for $10,313,000 principal amount of the 14% Senior Subordinated Notes at a price of 114% of the principal amount plus accrued interest. This transaction resulted in a loss of approximately $2,561,000. On January 14, 2002 the Company exercised its right of redemption for $35,403,000 principal amount of the 14% Senior Subordinated Notes at a price of 114% of the principal amount plus accrued interest. This transaction resulted in a loss of approximately $8,468,000. Also, during the year ended June 30, 2002, the Company purchased and canceled $6,784,000 principal amount of the 14% Senior Subordinated Notes at a price of 116% of the principal amount plus accrued interest. These transactions resulted in losses of approximately $1,821,000.

The Unit Warrants have separated from the 14% Senior Subordinated Notes and became exercisable on January 25, 2000. On the date of issuance, the value of the Unit Warrants was estimated at $7,434,000 and is classified as a discount to the 14% Senior Subordinated Notes on the Company's consolidated balance sheet. The discount is being amortized to interest expense over the term of the 14% Senior Subordinated Notes. The 14% Senior Subordinated Notes mature and the Unit Warrants expire on January 15, 2009. The 14% Senior Subordinated Notes are subordinate to the Company's senior indebtedness, which includes borrowings under the Senior Credit Facility and the 8$^3/_8$% Senior Notes.

At December 31, 2002, $97,500,000 principal amount of the 14% Senior Subordinated Notes remained outstanding. The 14% Senior Subordinated Notes pay interest semi-annually on January 15 and July 15 of each year. Interest of approximately $6,825,000 was paid on July 15, 2002. As of December 31, 2002, 63,500 Unit Warrants had been exercised, producing approximately $4,173,000 of proceeds to the Company and leaving 86,500 Unit Warrants outstanding. As of December 31, 2002, the Company was in compliance with all covenants contained in the 14% Senior Subordinated Notes.

(iv) 5% Convertible Subordinated Notes

In 1997, the Company completed a private placement of $216,000,000 of 5% Convertible Subordinated Notes due 2004 (the "5% Convertible Subordinated Notes"). The 5% Convertible Subordinated Notes are subordinate to the Company's senior indebtedness which includes borrowings under the Senior Credit Facility, the 14% Senior Subordinated Notes and the 8$^3/_8$% Senior Notes. The 5% Convertible Subordinated Notes are convertible, at the holder's option, into shares of the Company's common stock at a conversion price of $38.50 per share, subject to certain adjustments. The 5% Convertible Subordinated Notes are redeemable, at the Company's option, on and after September 15, 2000, in whole or part, together with accrued and unpaid interest. The initial redemption price is 102.86% for the year beginning September 15, 2000 and declines ratably thereafter on an annual basis.

During the year ended June 30, 2001, the Company repurchased (and canceled) $47,384,000 principal amount of the 5% Convertible Subordinated Notes. These repurchases resulted in gains of approximately $4,564,000. During the year ended June 30, 2002, the Company repurchased (and canceled) $108,475,000 principal amount of the 5% Convertible Subordinated Notes, leaving $49,951,000 principal amount of the 5% Convertible Subordinated Notes outstanding at June 30, 2002. These repurchases resulted in gains of approximately $5,633,000. During the six months ended

December 31, 2002, the Company repurchased (and canceled) $397,000 principal amount of the 5% Convertible Subordinated Notes, leaving $49,554,000 principal amount of the 5% Convertible Subordinated Notes outstanding at December 31, 2002. The repurchases resulted in a gain of approximately $18,000. Interest on the 5% Convertible Subordinated Notes is payable on March 15 and September 15 of each year. Interest of approximately $1,244,000 was paid on September 15, 2002. As of December 31, 2002, the Company was in compliance with all covenants contained in the 5% Convertible Subordinated Notes.

Capitalized Debt Issuance Costs, Repayment Schedule and Interest Expense

The Company capitalized a total of approximately $3,026,000 in fees and costs in connection with the Senior Credit Facility and its 8$^3/_8$% Senior Notes during the six months ended December 31, 2002. The Company capitalized a total of approximately $1,877,000 and $4,958,000 in fees and costs in connection with its various financings during the years ended June 30, 2002 and 2001, respectively. The Company did not incur any fees or costs in connection with financing activities during the year ended June 30, 2000.

Presented below is a schedule of the repayment requirements of long-term debt (excluding the discount on the 14% Senior Subordinated Notes, the premium on the 8$^3/_8$% Senior Notes and the revolving loans under the Senior Credit Facility) for each of the next five years and thereafter as of December 31, 2002:

Year Ended December 31,		Principal Amount
		(Thousands)
2003	$	7,107
2004		7,106
2005		56,607
2006		
2007		
Thereafter		372,500
	$	443,320

The Company's interest expense for the six months ended December 31, 2002 and the years ended June 30, 2002, 2001, and 2000 consisted of the following:

	December 31, 2002	June 30, 2002	June 30, 2001	June 30, 2000

		June 30,		
		(Thousands)		
Cash payments for interest	$ 20,898	$ 42,085	$ 51,524	$ 61,956
Commitment and agency fees paid	730	1,183	1,203	1,139
Accretion of discount and premium on notes	52	424	739	743
Amortization of debt issuance costs	2,103	2,581	3,578	5,176
Net change in accrued interest	362	(1,275)	146	2,916
Capitalized interest	(1,402)	(1,666)	(630)	
	$ 22,743	$ 43,332	$ 56,560	$ 71,930

5. FAIR VALUE OF FINANCIAL INSTRUMENTS

The following table presents the carrying amounts and estimated fair values of the Company's financial instruments at December 31, 2002 and June 30, 2002 and June 30, 2001. FASB Statement

No. 107, "Disclosures about Fair Value of Financial Instruments," defines the fair value of a financial instrument as the amount at which the instrument could be exchanged in a current transaction between willing parties.

	December 31, 2002		June 30, 2002		June 30, 2001	
	Carrying Value	Fair Value	Carrying Value	Fair Value	Carrying Value	Fair Value
			(Thousands)			
Financial Assets:						
Cash and cash equivalents	$ 9,044	$ 9,044	$ 54,147	$ 54,147	$ 2,098	$ 2,098
Accounts receivable, net	141,958	141,958	117,907	117,907	177,016	177,016
Notes receivable related parties	251	251	274	274	6,050	6,600
Commodity option contracts	34	34	246	246	1,035	1,035
Financial Liabilities:						
Accounts payable	28,818	28,818	24,625	24,625	42,544	42,544
Commodity option contracts					344	344
Long-term debt:						
Senior Credit Facility	52,000	52,000			2,000	2,000
8$^{3}/_{8}$% Senior Notes	276,331	289,547	276,433	287,491	175,000	176,094
14% Senior Subordinated Notes	94,411	109,752	94,257	109,338	134,466	153,498
5% Convertible Subordinated Notes	49,554	47,324	49,951	46,942	158,426	141,989
Capital lease obligations	21,164	21,164	22,829	22,829	22,964	22,964
Other notes payable	105	105	140	140	1,051	1,051

The following methods and assumptions were used to estimate the fair value of each class of financial instruments:

Cash, trade receivables and trade payables: The carrying amounts approximate fair value because of the short maturity of those instruments.

Commodity option contracts: under SFAS 133, the carrying amount of the commodity option contracts approximate fair value. The fair value of the commodity option contracts is estimated using the discounted forward prices of each option's index price, for the term of each option contract.

Notes receivable related parties: The amounts reported relate to notes receivable from officers and other employees of the Company.

Long-term debt: The fair value of the Company's long-term debt is based upon the quoted market prices for the various notes and debentures at December 31, 2002 and June 30, 2002 and 2001, and the carrying amounts outstanding under the Company's senior credit facility then outstanding.

6. DERIVATIVE FINANCIAL INSTRUMENTS

The Company utilizes derivative financial instruments to manage well defined commodity price risks. The Company is exposed to credit losses in the event of nonperformance by the counter-parties to its commodity hedges. The Company only deals with reputable financial institutions as counter-parties and anticipates that such counter-parties will be able to fully satisfy their obligations under the contracts. The Company does not obtain collateral or other security to support financial instruments subject to credit risk but monitors the credit standing of the counter-parties.

The Company periodically hedges a portion of its oil and natural gas production through collar and option agreements. The purpose of the hedges is to provide a measure of stability in the volatile environment of oil and natural gas prices and to manage exposure to commodity price risk under

existing sales commitments. The Company's risk management objective is to lock in a range of pricing for expected production volumes. This allows the Company to forecast future earnings within a predictable range. The Company meets this objective by entering into collar and option arrangements which allow for acceptable cap and floor prices.

The Company does not enter into derivative instruments for any purpose other than for economic hedging. The Company does not speculate using derivative instruments. The Company has identified the following derivative instruments:

Freestanding Derivatives. On March 30, 2000 the Company entered into a collar arrangement for a 22-month period whereby the Company will pay if the specified price is above the cap index and the counter-party will pay if the price should fall below the floor index. The hedge defines a range of cash flows bounded by the cap and floor prices. On May 25, 2001 the Company entered into an option arrangement for a 12-month period beginning March 2002 whereby the counter-party will pay if the price should fall below the floor index. On May 2, 2002 the Company entered into an option arrangement for a 12-month period beginning March 2003 whereby the counter-party will pay if the price should fall below the floor index. The Company desires a measure of stability to ensure that cash flows do not fall below a certain level.

Prior to the adoption of SFAS 133 as discussed in Note 1, these collars and options were accounted for as cash flow type hedges. Accordingly, the transition adjustment resulted in recording a $778,000 liability for the fair value of the collars and an offset to accumulated other comprehensive income. The transition adjustment to accumulated other comprehensive income of approximately $258,000 and $520,000 was recognized in earnings during the years ended June 30, 2002 and 2001, respectively. While this arrangement was intended to be an economic hedge, as of July 1, 2000, the Company had not documented the March 30, 2000 oil and natural gas collars as cash flow hedges and therefore reported a charge to operations of approximately $565,000 for the increase in fair value of the liability as of September 30, 2000 in other income. As of October 1, 2000, the Company documented these collars as cash flow hedges. As of May 25, 2001, the Company had not documented the May 25, 2001 oil and natural gas options as cash flow hedges and therefore has included income of $768,000 for the increase in fair value of the asset as of June 30, 2001 in other income. As of July 1, 2001, the Company documented these options as cash flow hedges. As of May 2, 2002, the Company had documented the May 2, 2002 oil and natural gas options as cash flow hedges. The Company recorded a net decrease in derivative assets net of derivative liabilities of $51,000 during the six months ended December 31, 2002. The Company recorded a net decrease in derivative assets net of derivative liabilities of $543,000 and a net increase of $999,000 during the years ended June 30, 2002 and 2001, respectively.

The Company recorded no ineffectiveness for the six months ended December 31, 2002 and recorded in earnings an ineffectiveness expense of $85,000 and ineffectiveness income of $132,000 for the years ended June 30, 2002 and 2001, respectively.

Embedded Derivatives. The Company is party to a volumetric production payment that meets the definition of an embedded derivative under SFAS 133. Effective July 1, 2000, the Company determined and documented that the volumetric production payment is excluded from the scope of SFAS 133 under the normal purchases/sales exclusion as set forth in SFAS 138.

For the year ended June 30, 2000, gains and amortization of premiums paid on option contracts are recognized as an adjustment to sales revenue when the related transactions being hedged are finalized. The net effect of the Company's commodity hedging activities decreased oil and natural gas revenues for the year ended June 30, 2000 by approximately $822,000.

The following table sets forth the future volumes hedged by year and the weighted-average strike price of the option contracts at December 31, 2002 and June 30, 2002 and 2001:

	Monthly Income			Strike Price Per Bbl/Mmbtu		
	Oil (Bbls)	Gas (Mmbtu)	Term	Floor	Cap	Fair Value
At December 31, 2002						
Oil Put	5,000		Mar 2002 - Feb. 2003	$ 22.00		$
Oil Put	4,000		Mar 2003 - Feb. 2004	$ 21.00		$ 34,000
Gas Put		75,000	Mar 2002 - Feb. 2003	$ 3.00		$
At June 30, 2002						
Oil Put	5,000		Mar 2002 - Feb. 2003	$ 22.00		$ 24,000
Oil Put	4,000		Mar 2003 - Feb. 2004	$ 21.00		$ 118,000
Gas Put		75,000	Mar 2002 - Feb. 2003	$ 3.00		$ 104,000
At June 30, 2001						
Oil Collar	5,000		Mar 2001 - Feb. 2002	$ 19.70	$ 23.70	$ (115,000)
Oil Put	5,000		Mar 2002 - Feb. 2003	$ 22.00		$ 141,000
Gas Collar		40,000	Mar 2001 - Feb. 2002	$ 2.40	$ 2.91	$ (229,000)
Gas Put		75,000	Mar 2002 - Feb. 2003	$ 3.00		$ 894,000

(The strike prices for the oil collars and puts are based on the NYMEX spot price for West Texas Intermediate; the strike prices for the natural gas collars are based on the Inside FERC-West Texas Waha spot price; the strike price for the natural gas put is based on the Inside FERC-El Paso Permian spot price.)

7. OTHER ACCRUED LIABILITIES

Other accrued liabilities consist of the following:

	December 31, 2002	June 30, 2002	June 30, 2001
	(Thousands)		
Accrued payroll, taxes and employee benefits	$ 30,615	$ 28,479	$ 31,242
State sales, use and other taxes	2,292	2,344	5,825
Oil and natural gas revenue distribution	1,401	1,271	1,606
Other	23,515	17,371	10,250
Total	$ 57,823	$ 49,465	$ 48,923

Other non-current accrued expenses consist primarily of workers' compensation reserves.

8. STOCKHOLDERS' EQUITY

Equity Offerings

On December 19, 2001, the Company closed a public offering of 5,400,000 shares of common stock, yielding approximately $43.2 million, or $8.00 per share, to the Company (the "Equity Offering"). Net proceeds from the Equity Offering of approximately $42.6 million were used to temporarily reduce amounts outstanding under the Company's revolving line of credit. The net proceeds of the Equity Offering were ultimately used in January 2002 to redeem a portion of the Company's 14% Senior Subordinated Notes fully utilizing the Company's equity "claw-back" rights for up to 35% of the original $150 million issued.

On June 30, 2000, the Company closed a public offering of 11,000,000 shares of common stock at $9.625 per share, or approximately $106 million (the "2000 Equity Offering"). Net proceeds from the 2000 Equity Offering of approximately $101 million were used to repay a portion of the Company's term loan borrowings and revolving line of credit under its senior credit facility and retire other long-term debt.

Stock Incentive Plans

On January 13, 1998 the Company's shareholders approved the Key Energy Group, Inc. 1997 Incentive Plan, as amended (the "1997 Incentive Plan"). The 1997 Incentive Plan is an amendment and restatement of the plans formerly known as the "Key Energy Group, Inc. 1995 Stock Option Plan" (the "1995 Option Plan") and the "Key Energy Group, Inc. 1995 Outside Directors Stock Option Plan" (the "1995 Directors Plan") (collectively, the "Prior Plans").

All options previously granted under the Prior Plans and outstanding as of November 17, 1997 (the date on which the Company's board of directors adopted the plan) were assumed and continued, without modification, under the 1997 Incentive Plan.

Under the 1997 Incentive Plan, the Company may grant the following awards to key employees, directors who are not employees ("Outside Directors") and consultants of the Company, its controlled subsidiaries, and its parent corporation, if any: (i) incentive stock options ("ISOs") as defined in Section 422 of the Internal Revenue Code of 1986, as amended (the "Code"), (ii) "nonstatutory" stock options ("NSOs"), (iii) stock appreciation rights ("SARs"), (iv) shares of the restricted stock, (v) performance shares and performance units, (vi) other stock-based awards and (vii) supplemental tax bonuses (collectively, "Incentive Awards"). ISOs and NSOs are sometimes referred to collectively herein as "Options".

The Company may grant Incentive Awards covering an aggregate of the greater of (i) 3,000,000 shares of the Company's common stock and (ii) 10% of the shares of the Company's common stock issued and outstanding on the last day of each calendar quarter, provided, however, that a decrease in the number of issued and outstanding shares of the Company's common stock from the previous calendar quarter shall not result in a decrease in the number of shares available for issuance under the 1997 Incentive Plan. As a result of the Company's equity offerings discussed above, as of December 31, 2002, the number of shares of the Company's common stock that may be covered by Incentive Awards has increased to approximately 12.9 million.

Any shares of the Company's common stock that are issued and are forfeited or are subject to Incentive Awards under the 1997 Incentive Plan that expire or terminate for any reason will remain available for issuance with respect to the granting of Incentive Awards during the term of the 1997 Incentive Plan, except as may otherwise be provided by applicable law. Shares of the Company's common stock issued under the 1997 Incentive Plan may be either newly issued or treasury shares, including shares of the Company's common stock that the Company receives in connection with the exercise of an Incentive Award. The number and kind of securities that may be issued under the 1997 Incentive Plan and pursuant to then outstanding Incentive Awards are subject to adjustments to prevent enlargement or dilution of rights resulting from stock dividends, stock splits, recapitalizations, reorganization or similar transactions.

The maximum number of shares of the Company's common stock subject to Incentive Awards that may be granted or that may vest, as applicable, to any one Covered Employee (defined below) during any calendar year shall be 500,000 shares, subject to adjustment under the provisions of the 1997 Incentive Plan.

The maximum aggregate cash payout subject to Incentive Awards (including SARs, performance units and performance shares payable in cash, or other stock-based awards payable in cash) that may be granted to any one Covered Employee during any fiscal year is $2,500,000. For purposes of the 1997 Incentive Plan, "Covered Employees" means a named executive officer who is one of the group covered employees as defined in Section 162(m) of the Code and the regulation promulgated thereunder (i.e., generally the chief executive officer and the other four most highly compensated executive officers for a given year.)

The 1997 Incentive Plan is administrated by the Compensation Committee appointed by the Board of Directors (the "Committee") consisting of not less than two directors each of whom is (i) an "outside director" under Section 162(m) of the Code and (ii) a "non-employee director" under Rule 16b-3 of the Securities Exchange Act of 1934. In addition, subject to applicable shareholder approval requirements, the Company may issue NSOs outside the 1997 Incentive Plan.

The exercise price of options granted under the 1997 Incentive Plan and outside the 1997 Incentive Plan is at or above the fair market value per share on the date the options are granted. The exercise of NSOs results in a U.S. tax deduction to the Company equal to the income tax effect of the difference

between the exercise price and the market price at the exercise date. The following table summarizes the stock option activity related to the Company's plans (shares in thousands):

	Six Months Ended December 31, 2002		Year Ended June 30, 2002		Year Ended June 30, 2001		Year Ended June 30, 2000	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Outstanding:								
Beginning of period	10,008	$ 7.80	8,703	$ 7.49	9,470	$ 6.37	6,920	$ 5.55
Granted	183	8.59	1,988	8.16	2,533	8.08	3,688	8.61
Exercised	(139)	3.12	(659)	4.53	(3,106)	4.70	(241)	4.56
Forfeited	(26)	7.00	(24)	4.86	(194)	4.92	(897)	9.80
End of period	10,026	7.88	10,008	7.80	8,703	7.49	9,470	6.37
Exercisable end of period	6,979		6,273		5,820		4,370	

The following table summarizes information about the stock options outstanding at December 31, 2002 (shares in thousands):

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Weighted-Average Remaining Contractual Life	Number of Shares Outstanding at December 31, 2002	Weighted-Average Exercise Price	Number of Shares Outstanding at December 31, 2002	Weighted-Average Exercise Price
$3.00 - $ 7.13	5.14	1,913	$ 4.75	1,548	5.06
$7.25 - $ 8.13	7.74	1,949	7.86	905	7.81
$8.25 - $ 8.31	6.71	2,080	8.26	1,968	8.26
$8.35 - $ 8.50	7.25	2,225	8.48	1,229	8.47
$8.88 - $13.25	6.88	1,859	9.97	1,329	10.34

The total fair value of stock options granted during the six months ended December 31, 2002 and the years ended June 30, 2002, 2001 and 2000 was approximately $747,000, $7,700,000, $11,217,000 and $19,541,000, respectively. The fair value of each stock option grant was estimated on the date of grant using the Black-Sholes option-pricing model, based on the following weighted-average assumptions.

Year Ended June 30,

	Six Months Ended December 31, 2002	Period of Grant 2002	2001	2000
Risk-free interest rate	2.73%	3.35%	4.30%	6.40%
Expected life of options	5 years	5 years	5 years	5 years
Expected volatility of the Company's stock price	52%	50%	59%	67%
Expected dividends	none	none	none	none

9. INCOME TAXES

Components of income tax expense (benefit) are as follows:

	Six Months Ended December 31, 2002	Year Ended June 30, 2002	2001	2000
			(Thousands)	
Federal and State:				
Current	$ 33	$ 914	$ 2,304	$ (5,588)
Deferred				
U.S.	(552)	21,385	34,953	(1,238)
Foreign				
Income tax expense (benefit)	$ (519)	$ 22,299	$ 37,257	(6,826)

The Company made federal income tax payments during the year ended June 30, 2002 which were refunded during the six months ended December 31, 2002. The Company made state income tax payments of approximately $234,000 and $1,767,000 during the six months ended December 31, 2002 and the year ended June 30, 2002, respectively. No federal or state income tax payments were made during the years ended June 30, 2001 or June 30, 2000. Additionally a deferred tax benefit of approximately $83,000, $267,000 and $7,004,000 has been allocated to stockholders' equity for the six months ended December 31, 2002 and the years ended June 30, 2002 and June 30, 2001, respectively, for compensation expense for income tax purposes in excess of amounts recognized for financial reporting purposes.

Income tax expense (benefit) differs from amounts computed by applying the statutory federal rate as follows:

	Six Months Ended December 31, 2002	Year Ended June 30, 2002	2001	2000
			(Thousands)	
Income tax computed at statutory rate	(35.0)%	35.0%	35.0%	(35.0)%
Amortization of goodwill disallowance			2.2	7.0
State taxes	1.6	2.8	1.4	
Change in valuation allowance and other	7.7	(0.9)	(1.4)	1.5
Income tax expense (benefit)	(25.7)%	36.9%	37.2%	(26.5)%

Deferred tax assets (liabilities) are comprised of the following:

	Six Months Ended December 31, 2002	Year Ended June 30, 2002	Year Ended June 30, 2001
		(Thousands)	
Net operating loss and tax credit carry forwards	$ 56,276	$ 50,089	$ 69,376
Property and equipment	(222,212)	(191,834)	(183,068)
Self insurance reserves	7,274	6,254	405
Allowance for bad debts	1,577	1,477	1,542
Asset retirement obligations	1,769		
Other	6,892	(2,456)	148
Net deferred tax liability	(148,424)	(136,470)	(111,597)
Valuation allowance for deferred tax assets	(12,841)	(13,520)	(15,803)
Net deferred tax liability, net of valuation allowance	$ (161,265)	$ (149,990)	$ (127,400)

A valuation allowance is provided when it is more likely than not that some portion of the deferred tax assets will not be realized. As described below, due to annual limitations on certain net operating loss carryforwards, it does not appear more likely than not that the Company will be able to utilize all available carryforwards prior to their ultimate expiration.

The Company estimates that as of December 31, 2002, the Company will have available approximately $161,443,000 of net operating loss carryforwards. Approximately $75,950,000 of the net operating loss carryforwards are subject to an annual limitation of approximately $2,028,000, under Sections 382 and 383 of the Internal Revenue Code.

10. OPERATING LEASING ARRANGEMENTS

The Company leases certain property and equipment under non-cancelable operating leases that generally expire at various dates through calendar 2007. The term of the operating leases generally run from 24 months to 60 months with varying payment dates throughout each month.

As of December 31, 2002, the future minimum lease payments under non-cancelable operating leases are as follows (in thousands):

Year Ending June 30,	Lease Payments
2003	$ 10,090
2004	9,038
2005	8,139
2006	5,136
2007	2,092
	$ 34,495

Operating lease expense was approximately $5,008,000 for the six months ended December 31, 2002 and $6,456,000, $6,072,000, and $6,460,000 for the years ended June 30, 2002, 2001 and 2000, respectively.

11. EMPLOYEE BENEFIT PLANS

In order to retain quality personnel, the Company maintains 401(k) plans as part of its employee benefits package. From January 1, 1999 through March 31, 2000, the Company elected not to match employee contributions. Commencing April 1, 2000, the Company matched 100% of employee contributions into its 401(k) plan up to a maximum of $250 per participant per year. The maximum limit was increased to $500 effective October 1, 2000, $750 effective January 1, 2001 and $1,000 effective July 1, 2001. The Company's matching contributions for the six months ended December 31, 2002 were approximately $888,000 and for the years ended June 30, 2002, 2001 and 2000 were approximately $2,123,000, $1,857,000 and $77,000, respectively.

12. TRANSACTIONS WITH RELATED PARTIES

Effective as of July 1, 2001, the Company entered into an amended and restated employment agreement with Francis D. John (the "Employment Agreement") pursuant to which Mr. John serves as the Chairman of the Board, President and Chief Executive Officer of the Company. The Employment Agreement provided for the payment of a one-time retention incentive payment. The purpose of this retention incentive payment was to retire all amounts owed by Mr. John under incentive-based loans previously made to him (which, because certain performance criteria had been previously met, the Company was scheduled to forgive ratably over a ten-year period as long as Mr. John continued to serve the Company in his present capacity) and in the process provide Mr. John with incentive to remain with the Company for the next ten years. On December 1, 2001, the incentive retention payment was paid to Mr. John and was comprised of two components: (i) approximately $7.5 million in principal and interest accrued through the date of the payment and (ii) approximately $5.6 million in a tax "gross-up" payment. The entire payment was withheld by the Company and used to satisfy Mr. John's tax obligations and his obligations under the loans. Pursuant to the Employment Agreement, Mr. John will earn the incentive retention payment over a ten-year period beginning July 1, 2001, with one-tenth of the total bonus being earned on June 30 of each year, beginning on June 30, 2002. For the six months ended December 31, 2002 and the year ended June 30, 2002, Mr. John earned approximately $0.6 and $1.3 million, respectively, of the retention incentive payment. If Mr. John voluntarily terminates his employment with the Company or if Mr. John is terminated by the Company for Cause (as defined in the Employment Agreement), Mr. John will be obligated to repay the entire remaining unearned balance of the retention incentive payment immediately upon such termination. However, if Mr. John's employment with the Company is terminated (i) by the Company other than for Cause, (ii) by Mr. John for Good Reason (as defined in the Employment Agreement), (iii) as a result of Mr. John's death or Disability (as defined in the Employment Agreement), or (iv) as a result of a Change in Control (as defined in the Employment Agreement), the remaining unearned balance of the retention incentive payment will be treated as earned as of the date of such event.

13. BUSINESS SEGMENT INFORMATION

The Company's reportable business segments are well servicing and contract drilling. Oil and natural gas production operations are presented in "corporate/other."

Well Servicing: The Company's operations provide well servicing (ongoing maintenance of existing oil and natural gas wells), workover (major repairs or modifications necessary to optimize the level of production from existing oil and natural gas wells) and production services (fluid hauling and fluid storage tank rental, fishing and rental tool services and pressure pumping services).

Contract Drilling: The Company provides contract drilling services for major and independent oil companies onshore the continental United States, Argentina and Ontario, Canada.

The Company's management evaluates the performance of its operating segments based on net income and operating profits (revenues less direct operating expenses). Corporate expenses include general corporate expenses associated with managing all reportable operating segments. Corporate

assets consist principally of cash and cash equivalents, deferred debt financing costs and deferred income tax assets.

	Well Servicing	Contract Drilling	Corporate /Other	Total
Six Months Ended December 31, 2002				
Operating revenues	$ 370,871	$ 33,632	$ 4,495	$ 408,998
Operating profit	107,276	10,216	2,561	120,053
Depreciation, depletion and amortization	43,982	4,799	2,330	51,111

	Well Servicing	Contract Drilling	Corporate /Other	Total
Interest expense	534		22,209	22,743
Net income (loss) before cumulative effect of a change in accounting principle*	19,492	1,504	(22,499)	(1,503)
Identifiable assets	834,019	90,534	255,179	1,179,732
Capital expenditures (excluding acquisitions)	27,422	3,894	10,180	41,496
Twelve Months Ended June 30, 2002				
Operating revenues	$ 706,629	$ 87,077	$ 8,858	$ 802,564
Operating profit	216,947	26,516	4,328	247,791
Depreciation, depletion and amortization	64,540	9,191	4,534	78,265
Interest expense	1,448		41,884	43,332
Net income (loss) before cumulative effect of a change in accounting principle*	76,547	7,630	(46,031)	38,146
Identifiable assets	686,425	91,374	264,127	1,041,926
Capital expenditures (excluding acquisitions)	57,857	19,861	15,979	93,697
Twelve Months Ended June 30, 2001				
Operating revenues	$ 758,273	$ 107,639	$ 7,350	$ 873,262
Operating profit	257,949	30,273	2,886	291,108
Depreciation, depletion and amortization	63,578	7,947	3,622	75,147
Interest expense	1,831		54,729	56,560
Net income (loss) before cumulative effect of a change in accounting principle*	109,159	9,466	(55,915)	62,710
Identifiable assets	664,611	95,473	278,325	1,038,409
Capital expenditures (excluding acquisitions)	51,064	15,884	15,802	82,750
Twelve Months Ended June 30, 2000				
Operating revenues	$ 559,492	$ 68,428	$ 9,812	$ 637,732
Operating profit	150,769	10,129	5,665	166,563
Depreciation, depletion and amortization	62,680	6,105	2,187	70,972
Interest expense	2,300		69,630	71,930
Net income (loss) before cumulative effect of a change in accounting principle*	48,062	(1,664)	(65,357)	(18,959)
Identifiable assets	635,304	89,574	322,754	1,047,632
Capital expenditures (excluding acquisitions)	26,469	8,282	3,422	38,173

* Net income (loss) before cumulative effect of a change in accounting principle for the contract drilling segment includes a portion of well servicing general and administrative expenses allocated on a percentage of revenue basis.

Operating revenues for the Company's foreign operations for the six months ended December 31, 2002 were $14.9 million and for the years ended June 30, 2002, 2001 and 2000 were $33.2 million, $54.5 million and $37.8 million, respectively. Operating profits for the Company's foreign operations for

the six months ended December 31, 2002 were $5.6 million and for the years ended June 30, 2002, 2001 and 2000 were $6.4 million, $13.4 million and $7.3 million, respectively.

The Company had $49.2 million, $27.9 million and $84.1 million of identifiable assets as of December 31, 2002 and June 30, 2002 and 2001, respectively, related to its foreign operations.

14. SUPPLEMENTAL SCHEDULE OF NONCASH INVESTING AND FINANCING ACTIVITIES

	Six Months Ended December 31, 2002	Year Ended June 30, 2002	2001	2000
		(Thousands)		
Fair value of common stock issued in purchase transactions	$ 159,946	$ 25,067	$ 8,120	
Fair value of common stock issued upon conversion of long-term debt			957	3,606
Capital lease obligations	3,107	10,047	9,595	10,758
Fair value of non-compete payment issued in purchase transaction	100			

15. UNAUDITED SUPPLEMENTARY INFORMATION QUARTERLY RESULTS OF OPERATIONS

Summarized quarterly financial data for the year ended December 31, 2002, and the years ended June 30, 2002 and 2001 are as follows:

	FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER
	(Thousands, Except Per Share Amounts)			
Year Ended December 31, 2002				
Revenues	$ 170,241	$ 169,749	$ 202,067	$ 206,931
Income (loss) before income taxes	1,408	(10,560)	(4,253)	2,231
Net income (loss) before cumulative effect of a change in accounting principle	(4,626)	(5,863)	(2,637)	1,134
Cumulative effect of a change in accounting principle, net of tax			(2,873)	
Net income (loss)	$ (4,626)	$ (5,863)	$ (5,510)	$ 1,134
Earnings (loss) per share:				
Basic before cumulative effect	$ (0.04)	$ (0.05)	$ (0.02)	$ 0.01
Cumulative effect, net of tax			(0.02)	
Basic after cumulative effect	$ (0.04)	$ (0.05)	$ (0.04)	$ 0.01
Diluted before cumulative effect	$ (0.04)	$ (0.05)	$ (0.02)	$ 0.01
Cumulative effect, net of tax			$ (0.02)	
Diluted after cumulative effect	$ (0.04)	$ (0.05)	$ (0.04)	$ 0.01
Weighted average shares outstanding:				
Basic	108,551	109,776	122,475	128,259
Diluted	110,059	109,776	122,475	129,294
Year Ended June 30, 2002				
Revenues	$ 249,237	$ 213,337	$ 170,241	$ 169,749
Income (loss) before income taxes	46,425	31,629	(7,060)	(10,549)

	FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER
Net income (loss)	$ 29,176	$ 19,459	$ (4,626)	$ (5,863)
Earnings (loss) per share:				
Basic	$ 0.29	$ 0.19	$ (0.04)	$ (0.05)
Diluted	$ 0.28	$ 0.19	$ (0.04)	$ (0.05)
Weighted average shares outstanding:				
Basic	101,727	103,115	108,551	109,776
Diluted	103,829	104,811	110,059	109,776
Year Ended June 30, 2001				
Revenues	$ 191,679	$ 203,911	$ 227,370	$ 250,302
Income (loss) before income taxes	14,178	18,172	27,647	39,970
Net income	$ 8,707	$ 11,162	$ 17,420	$ 25,421
Earnings per share:				
Basic	$ 0.09	$ 0.11	$ 0.18	$ 0.25
Diluted	$ 0.09	$ 0.11	$ 0.17	$ 0.24
Weighted average shares outstanding:				
Basic	96,880	97,534	98,211	100,179
Diluted	100,472	100,534	103,524	104,401

16. VOLUMETRIC PRODUCTION PAYMENT

In March 2000, Key sold a portion of its future oil and natural gas production from Odessa Exploration Incorporated, its wholly owned subsidiary, for gross proceeds of approximately $20 million pursuant to an agreement under which the purchaser is entitled to receive a share of the production from certain oil and natural gas properties in amounts ranging from 3,500 to 10,000 barrels of oil and 58,800 to 122,100 Mmbtus of natural gas per month over a six year period ending February 2006. The total volume of the forward sale is approximately 486,000 barrels of oil and 6.135 million Mmbtus of natural gas. In accordance with Statement of Financial Accounting Standards No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies, the net proceeds of the forward sale were recorded as deferred revenue and are recognized as income as the oil and gas is delivered.

17. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

The Company's senior notes are guaranteed by all of the Company's operating subsidiaries (except for its oil and natural gas production subsidiary and its foreign subsidiaries), all of which are wholly-owned. The guarantees are joint and several, full, complete and unconditional. There are currently no restrictions on the ability of the subsidiary guarantors to transfer funds to the parent company.

The accompanying condensed consolidating financial information has been prepared and presented pursuant to SEC Regulation S-X Rule 3-10 "Financial Statements of Guarantors and Issuers of Guaranteed Securities Registered or Being Registered." The information is not intended to present the financial position, results of operations and cash flows of the individual companies or groups of companies in accordance with accounting principles generally accepted in the United States of America.

CONDENSED CONSOLIDATING BALANCE SHEETS

DECEMBER 31, 2002

	PARENT COMPANY	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARIES	ELIMINATIONS	CONSOLIDATED
			(in thousands)		
Assets:					
Current assets	$ 17,716	$ 140,413	$ 17,445	$	$ 175,574
Net property and equipment	43,134	881,636	31,735		956,505
Goodwill, net	3,431	318,208	631		322,270
Deferred costs, net	13,503				13,503
Intercompany receivables	760,990			(760,990)	
Other assets	19,687	14,462	1		34,150
Total assets	$ 858,461	$ 1,354,719	$ 49,812	$ (760,990)	$ 1,502,002
Liabilities and equity:					
Current liabilities	$ 50,644	$ 54,278	$ 3,953	$	$ 108,875
Long-term debt	472,336				472,336
Capital lease obligations	1,648	12,573			14,221
Intercompany payables		725,442	35,548	(760,990)	
Deferred tax liability	161,265				161,265
Other long-term liabilities	28,530	20,289	118		48,937
Stockholders' equity	144,038	542,137	10,193		696,368
Total liabilities and stockholders' equity	$ 858,461	$ 1,354,719	$ 49,812	$ (760,990)	$ 1,502,002

	JUNE 30, 2002				
	PARENT COMPANY	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARIES	ELIMINATIONS	CONSOLIDATED
			(in thousands)		
Assets:					
Current assets	$ 64,814	$ 117,140	$ 10,119	$	$ 192,073
Net property and equipment	43,003	748,158	17,739		808,900
Goodwill, net	3,374	197,144	551		201,069
Deferred costs, net	12,580				12,580
Intercompany receivables	537,416			(537,416)	
Other assets	21,593	6,780			28,373
Total assets	$ 682,780	$ 1,069,222	$ 28,409	$ (537,416)	$ 1,242,995
Liabilities and equity:					
Current liabilities	$ 48,388	$ 45,427	$ 2,813	$	$ 96,628
Long-term debt	420,717				420,717
Capital lease obligations	1,457	13,762			15,219
Intercompany payables		516,761	20,655	(537,416)	
Deferred tax liability	149,990				149,990
Other long-term liabilities	13,474	10,101			23,575

	JUNE 30, 2002				
Stockholders' equity	48,754	483,171	4,941		536,866
Total liabilities and stockholders' equity	$ 682,780	$ 1,069,222	$ 28,409	$ (537,416)	$ 1,242,995

	JUNE 30, 2001				
	PARENT COMPANY	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARIES	ELIMINATIONS	CONSOLIDATED
	(in thousands)				
Assets:					
Current assets	$ 10,680	$ 165,653	$ 29,817	$	$ 206,150
Net property and equipment	21,418	717,989	54,309		793,716
Goodwill, net	3,374	184,379	2,122		189,875
Deferred costs, net	17,624				17,624
Intercompany receivables	664,592			(664,592)	
Other assets	15,303	5,616			20,919
Total assets	$ 732,991	$ 1,073,637	$ 86,248	$ (664,592)	$ 1,228,284
Liabilities and equity:					
Current liabilities	$ 35,671	$ 64,679	$ 15,203	$	$ 115,553
Long-term debt	470,578				470,578
Capital lease obligations	90	15,331	(38)		15,383
Intercompany payables		608,764	55,828	(664,592)	
Deferred tax liability	127,400				127,400
Other long-term liabilities	8,240	14,252			22,492
Stockholders' equity	91,012	370,611	15,255		476,878
Total liabilities and stockholders' equity	$ 732,991	$ 1,073,637	$ 86,248	$ (664,592)	$ 1,228,284

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

	SIX MONTHS ENDED DECEMBER 31, 2002				
	PARENT COMPANY	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARIES	ELIMINATIONS	CONSOLIDATED
	(in thousands)				
Revenues	$ 1,178	$ 392,900	$ 14,920	$	$ 408,998
Costs and expenses:					
Direct expenses		279,628	9,317		288,945

	SIX MONTHS ENDED DECEMBER 31, 2002				
Depreciation, depletion and amortization expense	1,392	48,892	827		51,111
General and administrative expense	17,187	30,258	794		48,239
Interest	22,209	410	124		22,743
Other	(18)				(18)
Total costs and expenses	40,770	359,188	11,062		411,020
Income (loss) before income taxes	(39,592)	33,712	3,858		(2,022)
Income tax (expense) benefit	10,163	(8,654)	(990)		519
Net income (loss) before cumulative effect of a change in accounting principle	(29,429)	25,058	2,868		(1,503)
Cumulative effect of a change in accounting principle, net of tax		(2,873)			(2,873)
Net income (loss)	$ (29,429)	$ 22,185	$ 2,868	$	$ (4,376)

	YEAR ENDED JUNE 30, 2002				
	PARENT COMPANY	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARIES	ELIMINATIONS	CONSOLIDATED
	(in thousands)				
Revenues	$ 1,247	$ 768,106	$ 33,211	$	$ 802,564
Costs and expenses:					
Direct expenses		527,977	26,796		554,773
Depreciation, depletion and amortization expense	1,830	73,252	3,183		78,265
General and administrative expense	22,715	34,481	2,298		59,494
Interest	41,883	857	592		43,332
Other	4,812		1,443		6,255
Total costs and expenses	71,240	636,567	34,312		742,119
Income (loss) before income taxes	(69,993)	131,539	(1,101)		60,445
Income tax (expense) benefit	25,820	(48,525)	406		(22,299)
Net income (loss)	$ (44,173)	$ 83,014	$ (695)	$	$ 38,146

	YEAR ENDED JUNE 30, 2001				
	PARENT COMPANY	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARIES	ELIMINATIONS	CONSOLIDATED
	(in thousands)				
Revenues	$ 2,018	$ 816,724	$ 54,520	$	$ 873,262
Costs and expenses:					
Direct expenses		540,987	41,167		582,154
Depreciation, depletion and amortization expense	1,353	69,714	4,080		75,147
General and administrative expense	19,158	37,558	3,402		60,118
Interest	54,464	1,275	821		56,560
Other	(684)				(684)
Total costs and expenses	74,291	649,534	49,470		773,295
Income (loss) before income taxes	(72,273)	167,190	5,050		99,967
Income tax (expense) benefit	26,935	(62,310)	(1,882)		(37,257)
Net income (loss)	$ (45,338)	$ 104,880	$ 3,168	$	$ 62,710

	YEAR ENDED JUNE 30, 2000				
	PARENT COMPANY	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARIES	ELIMINATIONS	CONSOLIDATED
	(in thousands)				
Revenues	$ 790	$ 599,225	$ 37,717	$	$ 637,732
Costs and expenses:					
Direct expenses		440,741	30,428		471,169
Depreciation, depletion and amortization expense	1,162	66,453	3,357		70,972
General and administrative expense	10,774	37,704	3,159		51,637
Interest	69,802	1,527	601		71,930
Other	(2,191)				(2,191)
Total costs and expenses	79,547	546,425	37,545		663,517
Income (loss) before income taxes	(78,757)	52,800	172		(25,785)
Income tax (expense) benefit	20,849	(13,977)	(46)		6,826
Net income (loss)	$ (57,908)	$ 38,823	$ 126	$	$ (18,959)

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

	SIX MONTHS ENDED DECEMBER 31, 2002				
	PARENT COMPANY	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARIES	ELIMINATIONS	CONSOLIDATED
	(in thousands)				
Net cash provided by operating activities	$ 18,562	$ 33,895	$ 5,137	$	$ 57,594
Net cash used in investing activities	(114,656)	(28,349)	(3,068)		(146,073)
Net cash provided by (used in) financing activities	48,535	(4,481)			44,054
Effect of exchange rate changes on cash			(678)		(678)
Net increase (decrease) in cash	(47,559)	1,065	1,391		(45,103)
Cash and cash equivalents at beginning of period	52,742	(157)	1,562		54,147
Cash and cash equivalents at end of period	$ 5,183	$ 908	$ 2,953	$	$ 9,044

	YEAR ENDED JUNE 30, 2002				
	PARENT COMPANY	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARIES	ELIMINATIONS	CONSOLIDATED
	(in thousands)				
Net cash provided by operating activities	$ 95,948	$ 78,577	$ 4,191	$	$ 178,716
Net cash used in investing activities	(37,188)	(67,092)	(4,469)		(108,749)
Net cash used in financing activities	(7,665)	(9,637)	(13)		(17,315)
Effect of exchange rate changes on cash			(603)		(603)
Net increase (decrease) in cash	51,095	1,848	(894)		52,049
Cash and cash equivalents at beginning of period	1,647	(2,005)	2,456		2,098
Cash and cash equivalents at end of period	$ 52,742	$ (157)	$ 1,562	$	$ 54,147

	YEAR ENDED JUNE 30, 2001				
	PARENT COMPANY	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARIES	ELIMINATIONS	CONSOLIDATED

	YEAR ENDED JUNE 30, 2001				
	(in thousands)				
Net cash provided by operating activities	$ 68,932	$ 64,673	$ 9,742	$	$ 143,347
Net cash used in investing activities	(19,824)	(56,976)	(7,180)		(83,980)
Net cash used in financing activities	(158,627)	(8,456)	(59)		(167,142)
Net increase (decrease) in cash	(109,519)	(759)	2,503		(107,775)
Cash and cash equivalents at beginning of period	111,166	(1,246)	(47)		109,873
Cash and cash equivalents at end of period	$ 1,647	$ (2,005)	$ 2,456	$	$ 2,098

	YEAR ENDED JUNE 30, 2000				
	PARENT COMPANY	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARIES	ELIMINATIONS	CONSOLIDATED
	(in thousands)				
Net cash provided by operating activities	$ 18,962	$ 10,434	$ 5,464	$	$ 34,860
Net cash used in investing activities	(4,468)	(26,671)	(6,627)		(37,766)
Net cash provided by (used in) financing activities	80,070	9,287	(56)		89,301
Net increase (decrease) in cash	94,564	(6,950)	(1,219)		86,395
Cash and cash equivalents at beginning of period	16,602	5,704	1,172		23,478
Cash and cash equivalents at end of period	$ 111,166	$ (1,246)	$ (47)	$	$ 109,873

18. ARGENTINA FOREIGN CURRENCY TRANSACTION LOSS

The local currency is the functional currency for the Company's foreign operations in Argentina and Canada. The cumulative translation gains and losses, resulting from translating each foreign subsidiary's financial statements from the functional currency to U.S. dollars are included in other comprehensive income and accumulated in stockholders' equity until a partial or complete sale or liquidation of the Company's net investment in the foreign entity.

Since 1991, the Argentine peso has been tied to the U.S. dollar at a conversion ratio of 1:1. However, in December 2001, the Government of Argentina announced an exchange holiday and, as a result, Argentine pesos could not be exchanged into other currencies at December 31, 2001. On January 5 and 6, 2002, the Argentine Congress and Senate gave the President of Argentina emergency powers and the ability to suspend the law that created the fixed conversion ratio of 1:1. The Government subsequently announced the creation of a dual currency system in which certain qualifying transactions will be settled at an expected fixed conversion ratio of 1.4:1 while all other transactions will be settled using a free floating market conversion ratio. Under existing guidance, dividends would not receive the fixed conversion ratio. On January 11, 2002, the exchange holiday was lifted, making it possible again to buy and sell Argentine pesos. Banks were legally allowed to exchange currencies, but transactions were limited and generally took place at exchange houses. These transactions were conducted primarily by individuals as opposed to commercial transactions, and occurred at free conversion ratios ranging between 1.6:1 and 1.7:1.

Due to the events described above, which resulted in the temporary lack of exchangeability of the two currencies at December 31, 2001, the Company translated the assets and liabilities of its Argentine subsidiary at December 31, 2001 using a conversion ratio of 1.6:1, which management believes was indicative of the free floating conversion ratio when the currency market re-opened on January 11, 2002. At December 31, 2002, the Company used a conversion ratio of 3.9:1 to translate the assets and liabilities of its Argentine subsidiary. As a result, a foreign currency translation loss of approximately $44.5 million is included in other comprehensive income, a component of stockholders' equity, at December 31, 2002. Since the 1:1 conversion ratio was in existence prior to December 2001, income statement and cash flows information for the six months ended December 31, 2001 has been translated using the historical 1:1 conversion ratio. After December 31, 2001, revenues and expenses are translated using the average exchange rate during the reporting period.

Additionally, the Argentine government has indicated that as part of its monetary policy changes, it will re-denominate certain consumer loans from U.S. dollar-denominated to Argentine peso-denominated. As a result, the Company recorded a foreign currency transaction loss of

$1.8 million in the three months ended December 31, 2001 related to accounts receivable subject to certain U.S. dollar-denominated contracts held by its Argentine subsidiary which are subject to re-denomination. These receivables are subject to additional negotiation with the Company's customers which may result in recovery of a portion of this loss. In the six months ended June 30, 2002, the Company recovered approximately $0.4 million resulting in a net foreign currency transaction loss of approximately $1.4 million for the year ended June 20, 2002.

19. GAINS (LOSSES) ON RETIREMENT OF DEBT ADOPTION OF SFAS 145

On July 1, 2002, the Company adopted Statement of Financial Accounting Standards No. 145, Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections ("SFAS 145"). The provisions of SFAS 145, which are currently applicable to the Company, rescind Statement No. 4, which required all gains and losses from extinguishment of debt to be aggregated and classified as an extraordinary item, and instead requires that such gains and losses be reported in operating income. The Company now records gains and losses from the extinguishment of debt in operating income and has reclassified such gains and losses in the financial statements for the years ended June 20, 2002, 2001 and 2000 to conform to the presentation for the six months ended December 31, 2002.

INDEPENDENT AUDITORS' REPORT

To The Board of Directors and Stockholders
Key Energy Services, Inc.

We have audited the accompanying consolidated balance sheets of Key Energy Services, Inc., and subsidiaries ("the Company") as of December 31, 2002 and June 30, 2002 and 2001, and the related consolidated statements of operations, comprehensive income, cash flows and stockholders' equity for the six months ended December 31, 2002 and each of the years in the three-year period ended June 30, 2002. In connection with our audits of the consolidated financial statements, we also have audited the financial statement schedule listed in the Index at Item 15. These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Key Energy Services, Inc. and subsidiaries as of December 31, 2002 and June 30, 2002 and 2001, and the results of their operations and their cash flows for the six months ended December 31, 2002 and each of the years in the three-year period ended June 30, 2002, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Note 1 to the consolidated financial statements, the Company changed its method of accounting for asset retirement obligations in the six months ended December 31, 2002, the Company changed its method of accounting for goodwill and other intangible assets in the year ended June 30, 2002, and the Company changed its method of accounting for derivative instruments and hedging activities in the year ended June 30, 2001.

KPMG LLP

Dallas, Texas
February 12, 2003

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KEY ENERGY SERVICES, INC.
CONSOLIDATED BALANCE SHEETS

	JUNE 30, 2003	DECEMBER 31, 2002
	(Unaudited) (Thousands, Except Share Data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 72,664	$ 9,044
Accounts receivable, net of allowance for doubtful accounts of $5,131 and $4,439, at June 30, 2003 and December 31, 2002, respectively	162,410	141,958
Inventories	13,491	10,243
Prepaid expenses and other current assets	13,061	14,329
Total current assets	261,626	175,574
Property and Equipment:		
Well servicing equipment	952,364	935,911
Contract drilling equipment	132,008	128,199
Motor vehicles	79,349	79,110
Oil and natural gas properties and other related equipment, successful efforts method	48,365	48,362
Furniture and equipment	58,208	51,349
Buildings and land	50,229	48,922
Total property and equipment	1,320,523	1,291,853
Accumulated depreciation and depletion	(382,879)	(335,348)
Net property and equipment	937,644	956,505
Goodwill, net	344,664	322,270
Deferred costs, net	14,765	13,503
Notes and accounts receivable related parties	191	251
Other assets	28,570	33,899

	JUNE 30, 2003	DECEMBER 31, 2002
Total assets	1,587,460	1,502,002
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable	$ 22,663	$ 28,818
Other accrued liabilities	63,148	57,823
Accrued interest	15,855	15,226
Current portion of long-term debt and capital lease obligations	6,441	7,008
Total current liabilities	108,107	108,875
Long-term debt, less current portion	539,506	472,336
Capital lease obligations, less current portion	12,753	14,221
Deferred revenue	6,570	8,460
Non-current accrued expenses	48,725	40,477
Deferred tax liability	153,309	161,265
Commitments and contingencies		
Stockholders' equity:		
Common stock, $.10 par value: 200,000,000 shares authorized, 130,051,496 and 128,757,693 shares issued, at June 30, 2003 and December 31, 2002, respectively	13,004	12,876
Additional paid-in capital	684,538	673,249
Treasury stock, at cost; 416,666 shares at June 30, 2003 and December 31, 2002	(9,682)	(9,682)
Accumulated other comprehensive income (loss)	(39,111)	(45,431)
Retained earnings (deficit)	69,741	65,356
Total stockholders' equity	718,490	696,368
Total liabilities and stockholders' equity	$ 1,587,460	$ 1,502,002

See the accompanying notes which are an integral part of these consolidated financial statements.

KEY ENERGY SERVICES, INC.
UNAUDITED CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
	(Thousands, Except Per Share Data)			
REVENUES				
Well servicing	$ 219,970	$ 154,051	$ 419,128	$ 308,485
Contract drilling	18,511	13,130	33,106	27,092
Other	1,114	2,568	2,485	4,413
Total Revenues	239,595	169,749	454,719	339,990

	Three Months Ended June 30,		Six Months Ended June 30,	
COSTS AND EXPENSES:				
Well servicing	154,333	121,003	301,238	234,361
Contract drilling	13,189	10,387	24,337	21,453
Depreciation, depletion and amortization	25,690	20,783	51,291	40,672
General and administrative	23,585	16,881	45,703	30,575
Interest	12,166	10,411	23,214	20,286
Other expenses	974	1,245	1,889	2,196
Foreign currency transaction gain, Argentina		(401)		(401)
(Gain) loss on retirement of debt	(14)	(11)	(16)	8,457
	229,923	180,298	447,656	357,599
Income (loss) before income taxes	9,672	(10,549)	7,063	(17,609)
Income tax (expense)	(3,519)	4,686	(2,684)	7,120
NET INCOME (LOSS)	$ 6,153	$ (5,863)	$ 4,379	$ (10,489)
EARNINGS (LOSS) PER SHARE:				
Net income (loss)				
Basic	$ 0.05	$ (0.05)	$ 0.03	$ (0.10)
Diluted	0.05	(0.05)	0.03	(0.10)
WEIGHTED AVERAGE SHARES OUTSTANDING:				
Basic	129,128	109,776	128,765	109,225
Diluted	131,356	109,776	130,761	109,225

See the accompanying notes which are an integral part of these consolidated financial statements.

KEY ENERGY SERVICES, INC.
UNAUDITED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
	(In Thousands)			
CASH FLOWS FROM OPERATING ACTIVITIES:				
Net income (loss)	$ 6,153	$ (5,863)	$ 4,379	$ (10,489)
ADJUSTMENTS TO RECONCILE NET INCOME (LOSS) TO NET CASH PROVIDED BY OPERATING ACTIVITIES:				
Depreciation, depletion and amortization	25,690	20,783	51,291	40,672
Amortization of deferred debt issuance costs, discount and premium	833	612	1,609	1,282
Deferred income tax expense (benefit)	3,198	(2,189)	2,303	(2,320)
Loss on sale of assets	235	16	291	162

	Three Months Ended June 30,		Six Months Ended June 30,	
Foreign currency transaction gain, Argentina		(401)		(401)
(Gain) loss on retirement of debt	(14)	(11)	(16)	8,457
CHANGE IN ASSETS AND LIABILITIES, NET OF EFFECTS FROM ACQUISITIONS:				
(Increase) decrease in accounts receivable	(11,026)	1,848	(21,139)	25,696
Increase in other current assets	(736)	(1,982)	(686)	(1,913)
Increase in accounts payable, accrued interest and accrued expenses	10,924	22,249	735	7,286
Other assets and liabilities	4,882	9,824	9,433	6,733
Net cash provided by operating activities	40,139	44,886	48,200	75,165
CASH FLOWS FROM INVESTING ACTIVITIES:				
Capital expenditures well servicing	(15,386)	(16,098)	(31,079)	(29,456)
Capital expenditures contract drilling	(3,073)	(5,658)	(4,003)	(8,784)
Capital expenditures other	(5,177)	(7,373)	(7,772)	(9,795)
Proceeds from sale of fixed assets	565	296	1,520	603
Acquisitions well servicing, net of cash acquired	(3,689)	(396)	(4,248)	(8,598)
Acquisitions contract drilling, net of cash acquired		(2,037)		(2,037)
Net cash provided by (used in) investing activities	(26,760)	(31,266)	(45,582)	(58,067)
CASH FLOWS FROM FINANCING ACTIVITIES:				
Repayment of long-term debt.	(101,632)	(846)	(107,697)	(124,628)
Repayment of capital lease obligations	(2,372)	(2,451)	(4,799)	(5,183)
Proceeds from long-term debt.	162,000		175,000	159,500
Proceeds paid for debt issuance costs	(2,963)		(2,963)	(1,585)
Proceeds from exercise of stock options	1,482	1,405	2,113	1,599
Other		(214)	(25)	(209)
Net cash provided by financing activities	56,515	(2,106)	61,629	29,494
Effect of exchange rates on cash	(792)	(334)	(627)	(411)
Net increase (decrease) in cash and cash equivalents	69,102	11,180	63,620	46,181
Cash and cash equivalents at beginning of period	3,562	42,967	9,044	7,966
Cash and cash equivalents at end of period	$ 72,664	$ 54,147	$ 72,664	$ 54,147

See the accompanying notes which are an integral part of these consolidated financial statements.

KEY ENERGY SERVICES, INC.
UNAUDITED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
	(In Thousands)			
NET INCOME (LOSS), NET OF TAX	$ 6,153	$ (5,863)	$ 4,379	$ (10,489)
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX:				
Oil and natural gas derivatives adjustment, net of tax	(24)	(177)	(39)	(636)
Amortization of oil and natural gas derivatives, net of tax	18	144	695	(179)
Foreign currency translation gain (loss), net of tax	2,353	(4,850)	5,664	(24,158)
COMPREHENSIVE INCOME (LOSS), NET OF TAX	$ 8,500	$ (10,746)	$ 10,699	$ (35,462)

See the accompanying notes which are an integral part of these consolidated financial statements.

KEY ENERGY SERVICES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

JUNE 30, 2003 AND 2002

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

BASIS OF PRESENTATION

The consolidated financial statements of Key Energy Services, Inc. (the "Company" or "Key") and its wholly-owned subsidiaries as of June 30, 2003 and for the three and six month periods ended June 30, 2003 and 2002 are unaudited. Certain information and footnote disclosures normally included in financial statements prepared in accordance with generally accepted accounting principles have been condensed or omitted in this Form 10-Q pursuant to the rules and regulations of the Securities and Exchange Commission (the "SEC"). However, in the opinion of management, these interim financial statements include all the necessary adjustments to fairly present the results of the interim periods presented. These unaudited interim consolidated financial statements should be read in conjunction with the audited financial statements included in the Company's Transition Report on Form 10-K for the fiscal year ended December 31, 2002. The results of operations for the three and six month periods ended June 30, 2003 are not necessarily indicative of the results of operations for the full fiscal year ending December 31, 2003.

STOCK BASED COMPENSATION

The Company accounts for stock option grants to employees using the intrinsic value method of accounting prescribed by APB Opinion No. 25 ("APB 25"), "Accounting for Stock Issued to Employees." Under the Company's stock incentive plan, the price of the stock on the grant date is the same as the amount an employee must pay to exercise the option to acquire the stock. Accordingly, the options have no intrinsic value at grant date, and in accordance with the provisions of APB 25, no compensation cost is recognized.

Statement of Financial Accounting Standards No. 123 ("SFAS 123"), "Accounting for Stock-Based Compensation," sets forth alternative accounting and disclosure requirements for stock-based compensation arrangements. Companies may continue to follow the provisions of APB 25 to measure and recognize employee stock-based compensation; however, SFAS 123 requires disclosure of pro forma net income and earnings per share that would have been reported under the fair value based recognition provisions of SFAS 123. The following table illustrates the effect on net income and earnings per share if the Company had applied the fair value recognition provisions of SFAS 123 to stock-based employee compensation:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
	(Thousands, except per share data)			
Net income (loss):	$ 6,153	$ (5,863)	$ 4,379	$ (10,489)
As reported				
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of tax	(2,191)	(2,651)	(4,504)	(6,013)
Pro forma	$ 3,962	$ (8,514)	$ (125)	$ (16,502)
Basic earnings per share:				
As reported	$ 0.05	$ (0.05)	$ 0.03	$ (0.10)
Pro forma	$ 0.03	$ (0.08)	$	$ (0.15)
Diluted earnings per share:				
As reported	$ 0.05	$ (0.05)	$ 0.03	$ (0.10)
Pro forma	$ 0.03	$ (0.08)	$	$ (0.15)

Reclassifications

Certain reclassifications have been made to the consolidated financial statements for the three and six months ended June 30, 2002 to conform to the presentation for the three and six months ended June 30, 2003. The reclassifications consist primarily of gains (losses) on the retirement of debt which are now being recorded as operating expenses rather than as extraordinary items in accordance with SFAS 145, which the Company adopted on July 1, 2002 (See Note 11). In addition, certain property and equipment of the Company, which may be used in either well servicing or drilling that had been previously classified as drilling has now been reclassified as well servicing along with related operating results. The reclassification was made because the majority of the services performed are well servicing in nature.

2. ASSET RETIREMENT OBLIGATIONS SFAS 143

On July 1, 2002, the Company adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations ("SFAS 143"). The new standard requires the Company to recognize a liability for the present value of all legal obligations associated with the retirement of tangible long-lived assets and capitalize an equal amount as a cost of the asset depreciating the additional cost over the estimated useful life of the asset. At June 30, 2003 and December 31, 2002, the asset retirement obligation was approximately $9,456,000 and $9,231,000, respectively, related to expected abandonment costs of its oil and natural gas producing properties and salt water disposal wells. The increase in the balance from December 31, 2002 of approximately $225,000 is due to accretion of the discounted liability.

3. GOODWILL AND OTHER INTANGIBLE ASSETS SFAS 142

The Company follow the provisions of Statement of Financial Accounting Standards No. 142, Goodwill and Other Intangible Assets ("SFAS 142"). SFAS 142 eliminates the amortization for goodwill and other intangible assets with indefinite lives. Intangible assets with lives restricted by contractual, legal, or other means will continue to be amortized over their useful lives. Goodwill and other intangible assets not subject to amortization are tested for impairment annually or more frequently if events or changes in circumstances indicate that the asset might be impaired. SFAS 142 requires a

two-step process for testing impairment. First, the fair value of each reporting unit is compared to its carrying value to determine whether an indication of impairment exists. If impairment is indicated, then the fair value of the reporting unit's goodwill is determined by allocating the unit's fair value to its assets and liabilities (including any unrecognized intangible assets) as if the reporting unit had been acquired in a business combination. The amount of impairment for goodwill is measured as the excess of its carrying value over its fair value. The Company completed its most recent assessment of goodwill impairment as of June 30, 2003. The assessment did not result in an indication of goodwill impairment.

Intangible assets subject to amortization under SFAS 142 consist of noncompete agreements and patents. Amortization expense for the noncompete agreements is calculated using the straight-line method over the period of the agreement, ranging from three to seven years. Amortization expense for patents is calculated using the straight-line method over the useful life of the patent, ranging from five to seven years.

The gross carrying amount of noncompete agreements subject to amortization totaled approximately $16,143,000 and $18,669,000 at June 30, 2003 and December 31, 2002, respectively. Accumulated amortization related to these intangible assets totaled approximately $6,198,000 and $7,511,000 at June 30, 2003 and December 31, 2002, respectively. Amortization expense for the three months ended June 30, 2003 and 2002 was approximately $1,013,000 and $729,000, respectively. Amortization expense for the six months ended June 30, 2003 and 2002 was approximately $2,132,000 and $1,144,000, respectively. Amortization expense for the next five succeeding years is estimated to be approximately $3,554,000, $2,691,000, $2,067,000, $1,498,000 and $117,000.

The gross carrying amount of patents subject to amortization totaled approximately $2,454,000 and $2,380,000 at June 30, 2003 and December 31, 2002, respectively. Accumulated amortization related to these intangible assets totaled approximately $336,000 and $160,000 as of June 30, 2003 and December 31, 2002, respectively. The Company began acquiring patents on July 16, 2002. Amortization expense for the three and six months ended June 30, 2003 was approximately $88,000 and $176,000, respectively. Amortization expense for the next five succeeding years is estimated to be approximately $398,000, $398,000, $398,000, $398,000 and $286,000.

The Company has identified its reporting segments to be well servicing and contract drilling. Net goodwill allocated to such reporting segments at June 30, 2003 was approximately $330,346,000 and $14,318,000, respectively, and at December 31, 2002 was approximately $307,987,000 and $14,283,000, respectively. The change in carrying amount of goodwill for the three and six months ended June 30, 2003 was approximately $6,918,000 and $23,715,000, respectively, relates principally to the allocation of goodwill from the acquisition of Q Services, Inc. (See Note 5) and the preliminary allocation of goodwill from other small acquisitions, and the foreign currency translation adjustment for the Company's Argentina operations.

4. EARNINGS PER SHARE

The Company accounts for earnings per share based upon Statement of Financial Accounting Standards No. 128, "Earnings per Share" ("SFAS 128"). Under SFAS 128, basic earnings per common share are determined by dividing net earnings applicable to common stock by the weighted average number of common shares actually outstanding during the period. Diluted earnings per common share is based on the increased number of shares that would be outstanding assuming exercise of dilutive

stock options and warrants and conversion of dilutive outstanding convertible securities using the "as if converted" method.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	**2002**	**2003**	**2002**
	(Thousands, Except Per Share Data)			
BASIC EPS COMPUTATION:				
NUMERATOR				
Net income (loss)	$ 6,153	$ (5,863)	$ 4,379	$ (10,489)
DENOMINATOR				
Weighted average common shares outstanding	129,128	109,776	128,765	109,225
BASIC EPS:				
Net income (loss)	$ 0.05	$ (0.05)	$ 0.03	$ (0.10)

	Three Months Ended June 30,		Six Months Ended June 30,	
DILUTED EPS COMPUTATION:				
NUMERATOR				
Net income (loss)	$ 6,153	$ (5,863)	$ 4,379	$ (10,489)
DENOMINATOR				
Weighted average common shares outstanding	129,128	109,776	128,765	109,225
Warrants	465		444	
Stock options	1,763		1,552	
	131,356	109,776	130,761	109,225
DILUTED EPS:				
Net income (loss)	$ 0.05	$ (0.05)	$ 0.03	$ (0.10)

The diluted earnings per share calculation for the three and six month periods ended June 30, 2003 excludes the effect of the potential exercise of 350,000 of the Company's stock options and the potential exercise of the Company's convertible debt because the effects of such instruments on earnings per share would be anti-dilutive. The diluted earnings per share calculation for the three months and six month periods ended June 30, 2002 excludes the effect of the potential exercise of the Company's convertible debt, outstanding warrants and stock options because the effects of such instruments on earnings per share would be anti-dilutive.

5. Q SERVICES ACQUISITION

On July 19, 2002, the Company acquired Q Services, Inc. ("QSI") pursuant to an Agreement and Plan of Merger dated May 13, 2002, as amended, by and among the Company, Key Merger Sub, Inc. and QSI. As consideration for the acquisition, the Company issued approximately 17.1 million shares of its common stock to the QSI shareholders and paid approximately $94.2 million in cash at the closing to retire debt and preferred stock of QSI and to satisfy certain other obligations of QSI. In addition to assuming the positive working capital of QSI, the Company incurred other direct acquisition costs and assumed certain other liabilities of QSI, resulting in the Company recording an aggregate purchase price of approximately $251 million. The value of the shares issued was based on the closing price of the Company's common stock on the closing date of $8.75 per share. The results of QSI's operations have been included in the consolidated financial statements since the closing date. Prior to the acquisition, QSI was a privately held corporation conducting field production, pressure pumping, and other service operations in Louisiana, New Mexico, Oklahoma, Texas, and the Gulf of Mexico. The Company and QSI operated in adjacent and/or overlapping locations and the Company expects to realize future cost savings and synergies in connection with the merger.

The following table summarizes the estimated preliminary fair value of the assets acquired and liabilities assumed at the date of acquisition:

	At July 19, 2002
	(Thousands)
Current assets	$ 37,734
Property and equipment	114,519
Intangible assets	3,242
Other assets	344
Goodwill	136,640
Total assets acquired	292,479

	At July 19, 2002
Current liabilities	18,597
Capital lease obligations	77
Non-current accrued expenses	17,908
Deferred tax liability	5,124
Total liabilities assumed	41,706
Net assets acquired	250,773

The $3,242,000 of intangible assets consists of noncompete agreements which have a weighted-average useful life of approximately two years. The $136,640,000 of goodwill was allocated to the well servicing reporting segment. Of that amount, $11,645,000 is expected to be deductible for income taxes.

During the three months ended March 31, 2003, the Company recorded an adjustment of approximately $24.5 million to reduce the cost allocated to certain equipment in the preliminary fair value allocation. The adjustment was based on an independent third party appraisal of the estimated fair value of the equipment as of the July 2002 acquisition date.

The following unaudited pro forma results of operations have been prepared as though QSI had been acquired on January 1, 2002. Pro forma amounts are not necessarily indicative of the results that may be reported in the future.

	Three Months Ended June 30, 2002	Six Months Ended June 30, 2002
	(Thousands, except per share data)	
Revenues	$ 208,654	$ 417,922
Net income (loss)	(7,846)	(11,271)
Basic earnings (loss) per share	$ (0.06)	$ (0.09)

6. SENIOR NOTES OFFERING

On May 14, 2003, the Company completed a public offering of $150,000,000 of $6^3/_8$% Senior Notes due 2013. The cash proceeds from the debt offering, net of fees and expenses, were used to repay the balance of the revolving loan facility then outstanding under the Company's senior credit facility, with the remainder to be used for general corporate purposes, including further debt retirement.

7. COMMITMENTS AND CONTINGENCIES

Various suits and claims arising in the ordinary course of business are pending against the Company. Management does not believe that the disposition of any of these items will result in a material adverse impact to the consolidated financial position, results of operations or cash flows of the Company.

8. DERIVATIVE FINANCIAL INSTRUMENTS

The Company utilizes derivative financial instruments to manage well defined commodity price risks. The Company is exposed to credit losses in the event of nonperformance by the counter-parties to its commodity hedges. The Company only deals with reputable financial institutions as counter-parties and anticipates that such counter-parties will be able to fully satisfy their obligations under the contracts. The Company does not obtain collateral or other security to support financial instruments subject to credit risk but monitors the credit standing of the counter-parties.

The Company periodically hedges a portion of its oil and natural gas production through collar and option agreements. The purpose of the hedges is to provide a measure of stability in the volatile environment of oil and natural gas prices and to manage exposure to commodity price risk under existing sales commitments. The Company's risk management objective is to lock in a range of pricing for expected production volumes. This allows the Company to forecast future cash flows within a predictable range. The Company meets this objective by entering into collar and option arrangements which allow for acceptable cap and floor prices. The Company desires a measure of stability to ensure that cash flows do not fall below a certain level.

The Company does not enter into derivative instruments for any purpose other than for economic hedging. The Company does not speculate using derivative instruments. The Company has identified the following derivative instruments:

Freestanding Derivatives. On May 25, 2001, the Company entered into an option arrangement for a 12-month period beginning March 2002 whereby the counter-party will pay if the oil and natural gas prices should fall below the floor index. On May 2, 2002, the Company entered into an option arrangement for a 12-month period beginning March 2003 whereby the counter-party will pay if the oil price should fall below the floor index.

The Company did not document the May 25, 2001 and May 2, 2002 oil and natural gas options as cash flow hedges until July 1, 2001 and July 1, 2002, respectively. The Company recorded a net decrease in derivative assets of approximately $27,000 and $778,000 during the six months ended June 30, 2003 and 2002, respectively. The Company recorded no ineffectiveness for the six months ended June 30, 2003 and an earnings charge of approximately $9,000 for the six months ended June 30, 2002.

The following table sets forth the future volumes hedged by year and the weighted-average strike price of the option contracts at June 30, 2003 and 2002:

	Oil (Bbls)	Gas (Mmbtus)	Term	Strike Price Per Bbl/Mmbtu Floor	Strike Price Per Bbl/Mmbtu Cap	Fair Value
At June 30, 2003						
Oil Put	4,000		Mar 2003 - Feb 2004	$ 21.00		$ 7,000
At June 30, 2002						
Oil Put	5,000		Mar 2002 - Feb 2003	$ 22.00		$ 24,000
Oil Put	4,000		Mar 2003 - Feb 2004	$ 21.00		$ 118,000
Natural Gas Put		75,000	Mar 2002 - Feb 2003	$ 3.00		$ 104,000

(The strike prices for the oil puts are based on the NYMEX spot prices for West Texas Intermediate. The strike price for the natural gas put is based on the Inside FERC-El Paso Permian spot price.)

9. BUSINESS SEGMENT INFORMATION

The Company's reportable business segments are well servicing and contract drilling. Oil and natural gas production operations are presented in "corporate/other."

Well Servicing: The Company's operations provide well servicing (ongoing maintenance of existing oil and natural gas wells), workover (major repairs or modifications necessary to optimize the level of production from existing oil and natural gas wells) and production services (fluid hauling and fluid storage tank rental, fishing and rental tool services and pressure pumping services).

Contract Drilling: The Company provides contract drilling services for major and independent oil companies onshore the continental United States, Argentina and Ontario, Canada.

The Company's management evaluates the performance of its operating segments based on net income and operating profits (revenues less direct operating expenses). Corporate expenses include general corporate expenses associated with managing all reportable operating segments. Corporate assets consist principally of cash and cash equivalents, deferred debt financing costs and deferred income tax assets.

	Well Servicing	Contract Drilling	Corporate/ Other	Total
Three Months Ended June 30, 2003				

	Well Servicing	Contract Drilling	Corporate/ Other	Total
Operating revenues	$ 219,970	$ 18,511	$ 1,114	$ 239,595
Operating profit	65,637	5,322	140	71,099
Depreciation, depletion and amortization	21,367	2,649	1,674	25,690
Interest expense	155		12,011	12,166
Net income (loss)*	13,332	566	(7,745)	6,153
Identifiable assets	817,648	89,258	335,890	1,242,796
Capital expenditures (excluding acquisitions)	15,386	3,073	5,177	23,636
Three Months Ended June 30, 2002				
Operating revenues	$ 154,051	$ 13,130	$ 2,568	$ 169,749
Operating profit	33,048	2,743	1,323	37,114
Depreciation, depletion and amortization	17,059	2,257	1,467	20,783
Interest expense	239		10,172	10,411
Net income (loss)*	225	(394)	(5,694)	(5,863)
Identifiable assets	686,423	91,374	264,129	1,041,926
Capital expenditures (excluding acquisitions)	16,098	5,658	7,373	29,129

* Net income (loss) for the contract drilling segment includes a portion of well servicing general and administrative expenses allocated on a percentage of revenue basis.

Operating revenues for the Company's foreign operations (which consists of Argentina, Canada and Egypt) for the three months ended June 30, 2003 and 2002 were approximately $12.3 million and $5.1 million, respectively. Operating profits for the Company's foreign operations for the three months ended June 30, 2003 and 2002 were approximately $4.8 million and $1.0 million, respectively. The Company had approximately $57.1 million and $27.9 million of identifiable assets as of June 30, 2003 and 2002, respectively, related to foreign operations. Capital expenditures for the Company's foreign

operations for the three months ended June 30, 2003 and 2002 were approximately $0.7 million and $0.4 million, respectively.

	Well Servicing	Contract Drilling	Corporate/ Other	Total
Six Months Ended June 30, 2003				
Operating revenues	$ 419,128	$ 33,106	$ 2,485	$ 454,719
Operating profit	117,890	8,769	596	127,255
Depreciation, depletion and amortization	42,917	5,212	3,162	51,291
Interest expense	339		22,875	23,214
Net income (loss)*	20,162	146	(15,929)	4,379
Identifiable assets	817,648	89,258	335,890	1,242,796
Capital expenditures (excluding acquisitions)	31,079	4,003	7,772	42,854
Six Months Ended June 30, 2002				
Operating revenues	$ 308,485	$ 27,092	$ 4,413	$ 339,990
Operating profit	74,124	5,639	2,217	81,980
Depreciation, depletion and amortization	33,512	4,608	2,552	40,672
Interest expense	495		19,791	20,286

	Well Servicing	Contract Drilling	Corporate/ Other	Total
Net income (loss)*	3,018	(1,227)	(12,280)	(10,489)
Identifiable assets	686,423	91,374	264,129	1,041,926
Capital expenditures (excluding acquisitions)	29,456	8,784	9,795	48,035

*
Net income (loss) for the contract drilling segment includes a portion of well servicing general and administrative expenses allocated on a percentage of revenue basis.

Operating revenues for the Company's foreign operations for the six months ended June 30, 2003 and 2002 were approximately $21.9 million and $9.2 million, respectively. Operating profits for the Company's foreign operations for the six months ended June 30, 2003 and 2002 were approximately $9.2 million and $1.7 million, respectively. The Company had approximately $57.1 million and $27.9 million of identifiable assets as of June 30, 2003 and 2002, respectively, related to foreign operations. Capital expenditures for the Company's foreign operations for the six months ended June 30, 2003 and 2002 were approximately $1.9 million and $3.1 million, respectively.

10. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

The Company's senior notes are guaranteed by substantially all of the Company's subsidiaries, all of which are wholly-owned. The guarantees are joint and several, full, complete and unconditional. There are currently no restrictions on the ability of the subsidiary guarantors to transfer funds to the parent company.

The accompanying condensed consolidating financial information has been prepared and presented pursuant to SEC Regulation S-X Rule 3-10 "Financial Statements of Guarantors and Issuers of Guaranteed Securities Registered or Being Registered." The information is not intended to present the financial position, results of operations and cash flows of the individual companies or groups of companies in accordance with accounting principles generally accepted in the United States of America.

The $6^3/_8$% Senior Notes are guaranteed by the Guarantor A group of subsidiaries, which consists of substantially all of the Company's subsidiaries. The $8^3/_8$% Senior Notes and the 14% Senior Subordinated Notes are guaranteed by the Guarantor A group of subsidiaries and Guarantor B, which is Odessa Exploration Incorporated.

CONDENSED CONSOLIDATING BALANCE SHEET

JUNE 30, 2003

	PARENT COMPANY	GUARANTOR A SUBSIDIARIES	GUARANTOR B SUBSIDIARY	NON-GUARANTOR SUBSIDIARIES	ELIMINATIONS	CONSOLIDATED
	(Thousands)					
Assets:						
Current assets	$ 83,987	$ 161,976	$ 1,242	$ 14,421	$	$ 261,626
Net property and equipment	48,659	833,797	31,506	23,682		937,644
Goodwill, net	3,431	340,475		758		344,664
Deferred costs, net	14,765					14,765
Inter-company receivables	726,164				(726,164)	

	JUNE 30, 2003					
Other assets	15,762	12,483	516			28,761
Total assets	$ 892,768	$ 1,348,731	$ 33,264	$ 38,861	$ (726,164)	$ 1,587,460
Liabilities and equity:						
Current liabilities	$ 38,179	$ 62,051	$ 2,104	$ 5,773	$	$ 108,107
Long-term debt	539,506					539,506
Capital lease obligations	1,516	11,237				12,753
Inter-company payables		692,964	15,705	17,495	(726,164)	
Deferred tax liability	153,309					153,309
Other long-term liabilities	39,269	4,236	11,678	112		55,295
Stockholders' equity	120,989	578,243	3,777	15,481		718,490
Total liabilities and stockholders' equity	$ 892,768	$ 1,348,731	$ 33,264	$ 38,861	$ (726,164)	$ 1,587,460

CONDENSED CONSOLIDATING BALANCE SHEET

	DECEMBER 31, 2002					
	PARENT COMPANY	GUARANTOR A SUBSIDIARIES	GUARANTOR B SUBSIDIARY	NON-GUARANTOR SUBSIDIARIES	ELIMINATIONS	CONSOLIDATED
	(Thousands)					
Assets:						
Current assets	$ 17,716	$ 142,587	$ 992	$ 14,279	$	$ 175,574
Net property and equipment	43,134	861,043	32,732	19,596		956,505
Goodwill, net	3,431	318,208		631		322,270
Deferred costs, net	13,503					13,503
Inter-company receivables	760,990				(760,990)	
Other assets	19,687	13,882	581			34,150
Total assets	$ 858,461	$ 1,335,720	$ 34,305	$ 34,506	$ (760,990)	$ 1,502,002
Liabilities and						

	DECEMBER 31, 2002					
equity:						
Current liabilities	$ 43,701	$ 59,410	$ 2,061	$ 3,703	$	$ 108,875
Long-term debt	472,336					472,336
Capital lease obligations	1,648	12,573				14,221
Inter-company payables		724,341	15,501	21,148	(760,990)	
Deferred tax liability	161,265					161,265
Other long-term liabilities	31,222	4,735	12,887	93		48,937
Stockholders' equity	148,289	534,661	3,856	9,562		696,368
Total liabilities and stockholders' equity	$ 858,461	$ 1,335,720	$ 34,305	$ 34,506	$ (760,990)	$ 1,502,002

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

	THREE MONTHS ENDED JUNE 30, 2003					
	PARENT COMPANY	GUARANTOR A SUBSIDIARIES	GUARANTOR B SUBSIDIARY	NON-GUARANTOR SUBSIDIARIES	ELIMINATIONS	CONSOLIDATED
	(Thousands)					
Revenues	$ 39	$ 230,767	$ 1,607	$ 7,182	$	$ 239,595
Costs and expenses:						
Direct expenses		161,880	1,056	5,560		168,496
Depreciation, depletion and amortization expense	1,101	23,355	614	620		25,690
General and administrative expense	10,243	12,636	267	439		23,585
Interest	12,010	136		20		12,166
Gain on retirement of debt	(14)					(14)
Total costs and expenses	23,340	198,007	1,937	6,639		229,923
Income (loss) before income taxes	(23,301)	32,760	(330)	543		9,672
Income tax (expense) benefit	10,082	(13,512)	150	(239)		(3,519)

	THREE MONTHS ENDED JUNE 30, 2003					
Net income (loss)	$ (13,219)	$ 19,248	$ (180)	$ 304	$	$ 6,153

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

THREE MONTHS ENDED JUNE 30, 2002

	PARENT COMPANY	GUARANTOR A SUBSIDIARIES	GUARANTOR B SUBSIDIARY	NON-GUARANTOR SUBSIDIARIES	ELIMINATIONS	CONSOLIDATED
			(Thousands)			
Revenues	$ 113	$ 162,937	$ 1,513	$ 5,186	$	$ 169,749
Costs and expenses:						
Direct expenses		127,205	1,266	4,164		132,635
Depreciation, depletion and amortization expense	626	18,848	870	439		20,783
General and administrative expense	7,267	9,147	141	326		16,881
Interest	10,172	235		4		10,411
Foreign currency transaction (gain), Argentina				(401)		(401)
Gain on retirement of debt	(11)					(11)
Total costs and expenses	18,054	155,435	2,277	4,532		180,298
Income (loss) before income taxes	(17,941)	7,502	(764)	654		(10,549)
Income tax (expense) benefit	8,670	(4,045)	302	(241)		4,686
Net income (loss)	$ (9,271)	$ 3,457	$ (462)	$ 413	$	$ (5,863)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

SIX MONTHS ENDED JUNE 30, 2003

PARENT COMPANY	GUARANTOR A SUBSIDIARIES	GUARANTOR B SUBSIDIARY	NON-GUARANTOR SUBSIDIARIES	ELIMINATIONS	CONSOLIDATED

SIX MONTHS ENDED JUNE 30, 2003

(Thousands)

Revenues	$ 107	$ 438,554	$ 2,970	$ 13,088	$	$ 454,719
Costs and expenses:						
Direct expenses		315,467	2,047	9,950		327,464
Depreciation, depletion and amortization expense	2,016	46,929	1,228	1,118		51,291
General and administrative expense	19,006	25,385	429	883		45,703
Interest	22,874	281		59		23,214
Gain on retirement of debt	(16)					(16)
Total costs and expenses	43,880	388,062	3,704	12,010		447,656
Income (loss) before income taxes	(43,773)	50,492	(734)	1,078		7,063
Income tax (expense) benefit	16,634	(19,187)	279	(410)		(2,684)
Net income (loss)	$ (27,139)	$ 31,305	$ (455)	$ 668	$	$ 4,379

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

SIX MONTHS ENDED JUNE 30, 2002

	PARENT COMPANY	GUARANTOR A SUBSIDIARY	GUARANTOR B SUBSIDIARY	NON-GUARANTOR SUBSIDIARIES	ELIMINATIONS	CONSOLIDATED
				(Thousands)		
Revenues	$ 423	$ 326,980	$ 3,369	$ 9,218	$	$ 339,990
Costs and expenses:						
Direct expenses		248,260	2,216	7,534		258,010
Depreciation, depletion and amortization expense	1,090	37,038	1,491	1,053		40,672
General and administrative expense	12,793	16,714	299	769		30,575
Interest	19,791	511		(16)		20,286
Foreign currency transaction (gain), Argentina				(401)		(401)
Gain on retirement of debt	8,457					8,457
Total costs and expenses	42,131	302,523	4,006	8,939		357,599
Income (loss) before income taxes	(41,708)	24,457	(637)	279		(17,609)
	16,864	(9,890)	258	(112)		7,120

	SIX MONTHS ENDED JUNE 30, 2002					
Income tax (expense) benefit						
Net income (loss)	$ (24,844)	$ 14,567	$ (379)	$ 167	$	$ (10,489)

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

	THREE MONTHS ENDED JUNE 30, 2003					
	PARENT COMPANY	GUARANTOR A SUBSIDIARIES	GUARANTOR B SUBSIDIARY	NON-GUARANTOR SUBSIDIARIES	ELIMINATIONS	CONSOLIDATED
	(Thousands)					
Net cash provided (used) by operating activities	$ 21,844	$ 19,011	$ (70)	$ (646)	$	$ 40,139
Net cash provided (used) in investing activities	(8,316)	(17,472)		(972)		(26,760)
Net cash provided (used) in financing activities	58,661	(2,146)				56,515
Effect of exchange rate changes on cash				(792)		(792)
Net increase (decrease) in cash	72,189	(607)	(70)	(2,410)		69,102
Cash at beginning of period	(1,271)	1,214	(204)	3,823		3,562
Cash at end of period	$ 70,918	$ 607	$ (274)	$ 1,413	$	$ 72,664

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

	THREE MONTHS ENDED JUNE 30, 2002					
	PARENT COMPANY	GUARANTOR A SUBSIDIARIES	GUARANTOR B SUBSIDIARY	NON-GUARANTOR SUBSIDIARIES	ELIMINATIONS	CONSOLIDATED
	(Thousands)					
Net cash provided (used) by operating activities	$ 28,542	$ 16,729	$ (1,506)	$ 1,121	$	$ 44,886
Net cash provided (used) in investing activities	(12,908)	(17,969)	176	(565)		(31,266)
Net cash provided (used) in financing activities	144	(2,250)				(2,106)
Effect of exchange rate changes on cash				(334)		(334)

THREE MONTHS ENDED JUNE 30, 2002

Net increase (decrease) in cash	15,778	(3,490)	(1,330)	222		11,180
Cash at beginning of period	36,964	3,728	935	1,340		42,967
Cash at end of period	$ 52,742	$ 238	$ (395)	$ 1,562	$	$ 54,147

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

SIX MONTHS ENDED JUNE 30, 2003

	PARENT COMPANY	GUARANTOR A SUBSIDIARIES	GUARANTOR B SUBSIDIARY	NON-GUARANTOR SUBSIDIARIES	ELIMINATIONS	CONSOLIDATED
			(Thousands)			
Net cash provided (used) by operating activities	$ 11,160	$ 36,477	$ (14)	$ 577	$	$ 48,200
Net cash provided (used) in investing activities	(11,387)	(32,757)	(2)	(1,436)		(45,582)
Net cash provided (used) in financing activities	65,962	(4,333)				61,629
Effect of exchange rate changes on cash				(627)		(627)
Net increase (decrease) in cash	65,735	(613)	(16)	(1,486)		63,620
Cash at beginning of period	5,183	1,220	(258)	2,899		9,044
Cash at end of period	$ 70,918	$ 607	$ (274)	$ 1,413	$	$ 72,664

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

SIX MONTHS ENDED JUNE 30, 2002

	PARENT COMPANY	GUARANTOR A SUBSIDIARIES	GUARANTOR B SUBSIDIARIES	NON-GUARANTOR SUBSIDIARIES	ELIMINATIONS	CONSOLIDATED
			(Thousands)			
Net cash provided (used) by operating activities	$ 40,343	$ 32,652	$ (1,250)	$ 3,420	$	$ 75,165
Net cash provided (used) in investing activities	(24,363)	(30,636)	62	(3,130)		(58,067)
Net cash provided (used) in financing	34,255	(4,761)				29,494

	SIX MONTHS ENDED JUNE 30, 2002					
activities						
Effect of exchange rate changes on cash				(411)		(411)
Net increase (decrease) in cash	50,235	(2,745)	(1,188)	(121)		46,181
Cash at beginning of period	2,507	2,983	793	1,683		7,966
Cash at end of period	$ 52,742	$ 238	$ (395)	$ 1,562	$	$ 54,147

11. GAINS (LOSSES) ON RETIREMENT OF DEBT SFAS 145

On July 1, 2002, the Company adopted Statement of Financial Accounting Standards No. 145, Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections ("SFAS 145"). The provisions of SFAS 145, which are currently applicable to the Company, rescind FASB Statement No. 4, which required all gains and losses from extinguishment of debt to be aggregated and classified as an extraordinary item, and instead requires that such gains and losses be reported in operating income. The Company now records gains and losses from the extinguishment of debt in operating income and has reclassified such gains and losses in the financial statements for the three and six months ended June 30, 2002 to conform to the presentation for the three and six months ended June 30, 2003.

QuickLinks